0000085511

Amended Application

E-01345A-08-0172

PART 2 OF 2

BAR CODE # 0000085511

To review Part 1 please see:

BAR CODE #0000085510

Donald E. Brandt

DIRECT TESTIMONY OF DONALD E. BRANDT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

Table of Contents

I. Introduction 1

II. Definitions of Important Terms 3

III. Summary 5

IV. APS Request 13

- A. Nature of the Request 13
- B. Key Issues 16

V. The Impact of Growth 17

- A. Growth in the APS Service Territory 17
- B. The Company's Capital Spending Requirements 18
- C. The Company's Rates Are Non-Compensatory 24
- D. APS's Deteriorating Financial Health 30
- E. Why Growth is Contributing to APS's Financial Pressure 51

VI. Actions the Company Has Taken to Address the Challenges of Growth. 60

VII. Actions the Commission Could Take to Help APS Cope With the Costs of Growth 66

- A. Attrition Adjustment 70
- B. Post-Test Year Plant In Rate Base 75
- C. Employee Incentive Compensation 78
- D. Supplemental Excess Benefit Retirement Plan ("SERP") 81
- E. Lobbying Costs 83

VIII. Conclusion 84

Behind the Rise in Prices ..... Attachment DEB-1

Transforming America's Power Industry: The Investment Challenge ..... Attachment DEB-2

APS Construction Expenditure Projection ..... Attachment DEB-3

Fitch Ratings Global Power Criteria Report and/or Standard & Poor's Corporate Ratings Matrix ..... Attachment DEB-4

APS Cost Containment Measures - 1/23/06 Letter ..... Attachment DEB-5

APS Lobbying Activity Highlights ..... Attachment DEB-6

DIRECT TESTIMONY OF DONALD E. BRANDT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald E. Brandt. I am President and Chief Executive Officer of Arizona Public Service Company ("APS" or "Company") and President and Chief Operating Officer of Pinnacle West Capital Corporation ("Pinnacle West"). I am responsible for all aspects of APS operations, including generation, transmission, distribution, customer service, and for general administrative functions. My business address is 400 North 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Business Administration with a major in Accounting from St. Louis University in 1975. Before joining Pinnacle West and APS in 2002, I was Senior Vice President and Chief Financial Officer of Ameren Corporation, the parent company of the electric and gas utilities Union Electric Company (d/b/a AmerenUE) and Central Illinois Public Service Company (d/b/a AmerenCIPS).

Before joining Union Electric Company in 1983, I was a manager with Price Waterhouse where I provided audit and consulting services to public companies, with a concentration in the utility industry. I am a certified public accountant and a member of the American Institute of Certified Public Accountants and the Arizona Society of Certified Public Accountants.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will summarize the central issues that required the Company to file a rate request just nine months after the Commission's entry of the Order in APS's last rate case, which case itself was filed just seven months after the Commission approved the 2004 APS Rate Settlement Agreement. In this testimony, I address the key issues facing the Company and the reason why, in the Company's current growth and capital expenditure environment, the traditional rate setting practice (based on an historic test year coupled with extensive regulatory lag) places the Company's financial health in constant jeopardy and invites a continuous stream of rate proceedings.

Q. HAS APS SUBMITTED OTHER DIRECT TESTIMONY IN SUPPORT OF ITS APPLICATION?

A. Yes. In addition to my testimony, APS has filed testimony by the following witnesses in the following areas.

Dr. William Avera	Cost of Equity
Mr. Daniel Kearns	Financial Projections, Attrition, Post Test Year Plant Additions, Pro Forma Rate Base and Operating Income Adjustments
Mr. Peter Ewen	Base Fuel Rate, Power Supply Adjustor, Revenue Forecast, Growth, Power Plant Maintenance, Electricity Sales Normalization
Mr. Jason LaBenz	Actual Test Year Results, Cost of Debt, Pro Forma Rate Base and Operating Income Adjustments, Calculation of Reconstruction Cost New Less Depreciation, Accounting Issues and Total Working Capital Requirements

Dr. Ronald White	Depreciation Expense
Mr. Patrick Dinkel	Yucca Units 5 and 6
Mr. David Rumolo	Cost of Service, Standard Filing Requirements, Transmission Cost Adjustor, Customer Impact Fees
Mr. David Pickles	Demand Side Management Policy
Mr. Gregory DeLizio	Service Schedules, Tariffs, Environmental Improvement Surcharge, Demand Side Management Adjustment Clause
Mr. Charles Miessner	Demand Response Rate Proposals

II. DEFINITIONS OF IMPORTANT TERMS

Q. PLEASE DEFINE ANY TERMS THAT MAY BE USEFUL IN UNDERSTANDING THE COMPANY'S APPLICATION.

A. To fully grasp the reasonably complicated financial concepts that are raised by the Company's Application, it is helpful to define and explain a few terms that will be used frequently by myself and other APS witnesses.

- "Revenue" is the gross amount of funds that the Company receives from selling electricity and other services to its customers.
- "Revenue Net of Fuel" or "Gross Margin" is the amount of net revenue that the Company receives from customers after deducting the costs of fuel and purchased power expenses.
- "Operating Expenses" are the on-going costs that the Company incurs to run its business, such as Operations and Maintenance expenses ("O&M"), and depreciation and property tax expenses incurred on the Company's capital projects once those projects are placed in service to customers.
- "Operating Margin" or "Operating Income" refers to the Company's Revenues less its fuel and purchased power costs and Operating Expenses.

- "Capital Costs" are the financing costs that the Company incurs to provide funds for its new capital and capital improvement projects. These capital projects are also referred to as construction projects, and include projects for APS power plants, transmission lines, substations, customer connections, computer systems, and buildings. These financing costs include both interest costs on APS debt and an equity return component on the investment by APS shareholders.

- "Carrying Costs" are the annual expenses associated with the depreciation, property taxes and Capital Costs associated with capital projects.

- "Net Income" or "Earnings" is Operating Margin less interest expense and income taxes. The Company's Net Income is the number that is divided by the Company's total equity to produce its Return on Equity, and represents the dollars that are available both for reinvestment in new infrastructure and for dividends. If Net Income does not increase at least as quickly as new equity investment, Attrition will result.

- A "Rate of Return" or "Return on Equity" ("ROE") is the ratio of the net income that the Company is able to earn relative to the amount of investment made by APS shareholders.

- "Attrition" refers to the erosion of the Company's earnings or ROE over time. Attrition invariably relates to a growth in Operating Expenses and/or Capital Costs that is more rapid than the Company's growth in its Gross Margin or Revenues Net of Fuel. Therefore, if Gross Margin does not increase as rapidly as Operating Expenses, earnings Attrition will occur. If Net Income does not increase as rapidly as equity investment, ROE Attrition will occur.

- "Incremental Costs" or "Marginal Costs" refer to the change to the Company's total costs that arises when APS produces one more unit (an additional kilowatt-hour, for example). "Incremental Revenue" or "Marginal Revenue," on the other hand, refers to the change to the Company's total Revenue that arises when APS sells an additional unit.

- "Fair Value" refers to the "fair value" of the Company's properties that are used to serve the public. A reasonable return on "fair value" is required as the basis for the determination of the Company's rates.

- "Regulatory Lag" refers to the timing gap between when the Company makes an expenditure in fulfillment of its regulatory obligation and when it begins to recover that expenditure through rates.

III. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS is the largest electric utility in the second fastest growing state in the United States (next only to Nevada). Although customer growth is not new to APS, the Company's increase in kilowatt (kW) demand has exceeded both its customer and sales growth. Historic economies of scale have largely been exhausted. At the same time, inflation in key commodities and materials such as fuel, copper, steel, and concrete, has caused costs—particularly construction and associated costs—to quickly rise. As a result, the Company's historic and continued customer growth, combined with the Company's ongoing investment in its existing electric system to maintain high levels of reliability and comply with increasing environmental restrictions, has caused APS's costs—particularly capital costs—to rise faster than revenues by significant amounts. Even with the recent downturn in the housing industry, APS still needs to spend **one billion dollars per year** on average for the foreseeable future in order to fulfill its duty to serve its existing and growing customer demand—an amount that is **double** the Company's annual capital spending for the past decade and that does not include any costs associated with new generation or new transmission related to such generation. Credit markets are worse now than they have been in recent memory, making APS's ability to borrow to meet these spending obligations difficult and costly.

While rising costs in a difficult credit market is a condition that plagues the entire electric industry, it is a particular source of financial stress for APS. The Company's enormous external capital requirements come at a time when APS's financial condition is already greatly weakened. APS's credit ratings hover just above the non-investment ("junk") grade, and its credit metrics are steadily declining. Just one more step down in APS's credit rating to junk could increase financing costs by up to a billion dollars over ten years and limit access to capital. The Company's inability to earn anything close to Commission-authorized equity returns makes additional equity financing difficult and expensive and puts the Company at almost the bottom in stock performance compared to other investor-owned electric utilities.

APS rates simply have not kept pace with the ever-growing increases in APS costs. While the rate increase authorized in Decision No. 69663 (June 29, 2007) went a long way towards solving much of the Company's fuel cost recovery problem, it did not solve, or, for that matter, even meaningfully address the Company's significant and increasing earnings shortfall. Importantly, not all rate increases will halt or improve a trend of declining earnings or underperforming ROE. Earnings are determined by subtracting from the Company's total Revenue all fuel and purchased power costs, Operating Expenses, interest expense and income taxes. In order for a rate increase to improve a company's earnings, it must provide the company with sufficient revenue to compensate it for the increases experienced in **each** of the expenses and costs that are included in the earnings calculation. In order to improve ROE, there must be yet additional revenue, net of taxes, to provide a reasonable return on the increased common equity since rates were last set. The rate

increase authorized in Decision No. 69663 did not provide for such revenue. While the improvements to the Company's Power Supply Adjustor ("PSA") and the new base fuel rate approved in that Decision allowed the Company recovery of its growing fuel and purchased power costs, that Decision did not compensate APS for the Company's significant increase in Operating Expenses and other non-fuel expenses. Only 0.3% of the total rate increase authorized by Decision No. 69663 was aimed at meeting APS's revenue requirement for non-fuel expenses. In fact, APS has not received any substantial non-fuel related rate increase since 1991, notwithstanding considerable inflation of the Company's non-fuel costs during that period. The Company's Operating Expenses, the vast majority of which are non-discretionary, have continued and are continuing to grow without any corresponding non-fuel revenue increases, and will thus drive the Company's earnings and ROE continually downward, further deteriorating APS's already precarious financial health and resulting in a massive cash flow deficit. From a state and local government perspective, one would refer to this condition as a "budget deficit." APS's current rate structure will not reverse that trend.

Many of the problems causing the imbalance between APS costs and revenues are largely outside of the Company's and the Commission's control, such as customer and sales growth, inflation, and the increasing capital and operating expenses that are required to maintain high levels of service reliability. But another significant part of the problem is inherent in Arizona's traditional rate-making process, which the Commission has the absolute ability to change.

The Commission generally sets the Company's rates based on average historical costs, and did so in Decision No. 69663. But when the Company's Marginal

Costs are higher than its average costs—as they are today in significant and increasing amounts—there is inevitable earnings attrition and erosion of financial metrics. In other words, for the reasons explained in this application, the cost to APS of adding each new customer, of producing and delivering each new kilowatt-hour, and of replacing or improving existing infrastructure is more expensive than the Company's average historic costs, on which APS's rates are based, and that cost continues to grow. This means that the revenue APS receives from rates set under the Commission's historic test year rate-setting methodology will always be insufficient to compensate the Company for its continually growing incremental costs, causing APS's financial health to further decline. In these circumstances, the combination of an historical test year and regulatory lag (that is, the length of time between when the Company incurs a cost and when it is permitted to recover that cost through rates)—without the simultaneous use of compensating cost-recovery mechanisms that acknowledge the continued rise in costs since the end of the historic test year—ensures that the Company's rates will remain inadequate to recover its costs and that significant attrition will continue.

In 2007, as SFR Schedule F-1 shows, APS earned an 8.7% ROE (0.4% of which was due to additional revenue received during an abnormally hot summer), compared to its authorized ROE of 10.75% (an allowed rate of return that is itself too low, as explained in the testimony of APS Expert Witness Dr. William Avera). Just in 2007, even with unusually hot weather bringing in unexpected revenue, the Company's earnings shortfall increased by $67 million, bringing the total earnings shortfall to $321 million over the past five years. Without action from this Commission, as Schedule F-1 makes clear, APS's ROE falls to

7.8% by the end of 2008, to 6.2% in 2009 and to an even further appalling 5.4% in 2010—numbers that do not improve much when measured on an ACC-jurisdictional basis. APS firmly believes that, absent timely relief from this Commission, a downgrade to junk credit status is inevitable.

But although APS faces the formidable challenge of continuing to provide reliable service in its current growth and regulatory lag environment, the challenge is not insurmountable. For its part, APS has taken and will continue to take steps on its own to address the challenges of growth and recover its financial health. Cost management is the most obvious Company responsibility, and APS has taken that responsibility seriously. As I will describe, APS is committed to effective cost-management and has recently undertaken a thorough cost analysis and APS-wide reorganization in an effort to ensure that its historical culture of operational efficiency continues during this difficult financial time.

In addition to managing its own costs, APS encourages its customers to do the same. With the Commission's support and with customer funding, APS has implemented a wide range of cost-effective Demand Side Management ("DSM") energy efficiency programs for customers. As the Commission knows, the Company's DSM programs have proven very successful. These programs can be expanded thus providing even more benefits if the Commission improves the current authorized DSM adjustor mechanism and removes the financial disincentives to such programs, as described in the testimony of APS Witnesses Greg DeLizio and David Pickles.

Rate design is another means of empowering customers to manage their own costs of energy. APS currently offers a broad menu of time and seasonally differentiated rates designed both to provide customers with the incentive to conserve energy during peak periods and to give customers an opportunity to reduce the size of their energy bills. The Company seeks to add additional innovative rate options with this filing, as Mr. DeLizio and APS Witness Charles Miessner explain in their testimony.

But cost-cutting measures and demand side management programs cannot and will not alone solve the Company's financial crisis. The historical and projected decline in APS's credit metrics have not been caused by reduced employee productivity, operational inefficiency, electric unreliability, or a reduced focus on customer service. Neither is it due to a failed risk management strategy or poor operational performance. The essential issue is that the Company's prices simply do not reflect the Company's cost of doing business – a factor largely within this Commission's control. While the Company was historically able to limit its cash outlay to what it brought in (operating on what was generally a balanced budget), APS is now required to spend substantially more cash than it collects, resulting in a cash flow "budget deficit" of hundreds of millions of dollars – and the Company cannot once again balance its cash budget without the Commission's help.

Notwithstanding APS's cost management and other efforts, APS still has a revenue requirement deficiency of $448.2 million (with an effective net increase to annual revenues of $278.2 million, as I will discuss below), for which it seeks recovery in this proceeding. Of this amount, $264.3 million (59% of the Company's total asking), is related to a substantial increase in the Company's

non-fuel costs, caused primarily by the Company's extensive construction program and increasing O&M expenses. The remaining portion of the Company's revenue requirement simply reclassifies what would be PSA revenues as base fuel revenues. This update to the base fuel rate results in only a small increase in electric prices to APS customers above what customers would see in any case under the normal operation of the PSA. After taking into consideration the reclassification of these fuel costs to base rates, the effective net increase in annual revenues sought in this application is $278.2 million. As for the attrition component of the Company's revenue requirement deficiency, the Commission has the opportunity to reduce the impact of this amount on existing customers and require growth to pay for more of the cost of growth by approving an impact fee charged to new applicants for electric service, as described in the testimony of APS Witness David Rumolo.

But while the revenue request sought in this application should allow the Company to stay within its current BBB- credit grade if timely granted, it will not allow APS to rise above that status and return to the higher credit ratings—and their attendant benefits—that the Company and its customers enjoyed just ten years ago. In this application, APS asks that the Commission recognize that, as efficiently as the Company operates and as innovative as it strives to be, it cannot invest in the infrastructure necessary to meet its customers' growing energy needs and implement its vision of a cleaner, more energy-efficient future without sufficient long-term financial health. That end depends on an ultimate goal of providing APS with a means to improve its financial condition for the long run, rather than a rate increase that suffices only to keep the Company teetering on the brink of junk grade, thus requiring a constant string of rate

proceedings. Sound long-term financial health for APS ultimately and importantly benefits the Company's customers in the form of comparably lower rates and reliable electric service—a fundamental necessity in an age of increasing reliance on energy. On the other hand, poor financial health for Arizona's largest utility creates the risk that necessary investments will be postponed or foregone and places Arizona's energy future in jeopardy—an outcome that cannot be ignored by either the Company or the Commission in response to short-term pressure to keep electric prices at an artificial minimum that is below APS's costs.

APS faces serious financial challenges that require innovative solutions from both the Company and the Commission. The Company asks that the Commission recognize in this proceeding that the historical test year rate setting practice traditionally used to set APS's rates can and should be adapted to address the challenges now confronting APS. This case proposes a number of solutions the Commission can adopt to help the Company secure financial health while continuing to provide reliable energy service to its growing customer base, including the inclusion in rate base of specific post-test year plant in which the Company had already invested before the end of the test year ended December 31, 2007 (the "Test Year") and that will be in service before rates in this case take effect, and an attrition adjustment that provides for sales and expense growth through 2010, the first full year that new rates from this case would be in place. Moreover, in addition to the Company's immediate revenue request, APS asks that the Commission work with the Company in this proceeding to develop a long-term plan that will identify innovative solutions to allow the Company to restore its financial health and return to high BBB (*ie.*,

BBB+ if not A-) credit rating status within the next several years, including a post-order proceeding to be conducted the year after rates from this case are set to ensure both that APS has the opportunity to earn its authorized rate of return and that it is on target for long-term financial stability and improvement.

In summary, growth and inflation are neither new nor unique to APS. What has changed is the trend of costs associated with that growth and inflation, the lack of available capacity to absorb growth, and the increasing inability of APS's rates and the traditional historic test year regulatory model to deal with this phenomenon. It is clear that the rates allowed under strict adherence to this model are simply not enough to preserve APS's financial condition and allow it the opportunity to continue to reliably serve its growing demand in the long run. In this demanding growth environment, the key towards achieving economic sustainability is to recognize and acknowledge some basic facts: (1) APS has a real problem that needs to be addressed; (2) the additional revenues from growth will not cover the costs required to meet growth, and APS will thus not "grow" out of the problem; (3) APS will not be able to cost-manage or cost-cut itself out of the problem; and (4) the historic test year rate-making model can and should be modified to help APS and its customers solve this problem.

IV. APS REQUEST

A. Nature of the Request

Q. PLEASE SUMMARIZE THE COMPANY'S REVENUE REQUEST.

A. APS seeks an effective net annual revenue increase of $278.2 million based on annualized Test Year sales—an amount that includes a $264.3 million increase in non-fuel base rates and a net increase to fuel-related electric rates of $13.9 million. The $448.2 million base rate increase sought in this application

includes $183.9 million of fuel and purchased power costs; however, the Company will recover $170.0 million of that amount under the normal operation of the PSA. Therefore, taking into consideration the reclassification of PSA revenues to base fuel revenues, as called for in the Commission-approved PSA Plan of Administration, the Company's effective net revenue increase request is $278.2 million. That amount can be further reduced by as much as $53 million if the Commission approves the Company's proposed impact fee as a means of offsetting a portion of its $79.3 million attrition adjustment, bringing the effective increase to base revenues down to $225.2 million.

The Company's overall request produces a 6.16% return on the Company's fair value rate base of $7.7 billion. A 6.16% return on fair value rate base is approximately equal on a dollar basis to APS's cost of capital (expressed in terms of return on original cost rate base) of 8.86%. Consistent with Commission practice for many years, fair value rate base is the arithmetic average of original cost rate base and reconstruction cost new rate base. The Company's request is significantly less than what would be justified under the fair value standard, as Dr. Avera explains in his testimony, and the Commission should carefully consider how to calculate fair value and the return thereon if its past method of doing so will not produce reasonable results in this case. APS Witness Jason LaBenz sponsors the weighted cost of capital calculation and Mr. Rumolo sponsors the fair value rate base calculation. The revenue requirement incorporates the Company's cost of capital at December 31, 2007. That cost of capital is, in turn, premised on an 11.5% cost of equity– a request on the low end of Dr. Avera's 11.25% to 12.5% scale of what would be a reasonable return on equity for investment in a utility with APS's current risk profile.

The Company is also offering new rate proposals in addition to changes to existing rates that will encourage customers to conserve energy, to promote and enhance the development and use of renewable resources, and to further protect Arizona's environment. As Mr. DeLizio and Mr. Miessner describe, these new rate proposals, along with changes to APS's existing rate designs, will provide additional opportunities for customers to save money on their monthly electric bills. APS believes that the super peak time-of-use and critical peak pricing rate designs described by Mr. Miessner will encourage customers to reduce consumption during the most critical hours of hot summer afternoons and early evenings. Mr. DeLizio will propose modifications to current rate schedules that will result in rates that are better tailored to our customers and that will provide a better opportunity for customers to shift usage to the off-peak hours. Mr. DeLizio will also support modifications both to the Environmental Improvement Surcharge ("EIS") in order to gain more timely recovery of actual investments in environmental improvements to APS generation units, and to the DSM Adjustor in order to allow for the expedited recovery of costs and expansion of APS energy efficiency programs. APS has also proposed that the Commission convert the Company's Transmission Cost Adjustor ("TCA") into a mechanism that allows the Company to properly reflect Federal Energy Regulatory Commission ("FERC") approved transmission prices in its retail rates, as Mr. Rumolo describes.

Based on the Commission's own "time clock" rules for the processing of general rate cases (A.A.C. R14-2-103), APS requests that its rate request become effective no later than October 1, 2009.

B. Key Issues

Q. HAS THE COMPANY RAISED ANY OTHER SIGNIFICANT ISSUES IN ITS APPLICATION?

A. Yes. As previously indicated, APS faces the critical challenge of maintaining its financial health in the face of capital spending obligations of one billion dollars per year for the next several years. The Commission has a constitutional obligation to set just and reasonable rates that will allow APS the opportunity to earn its cost of capital at the time those rates are fixed, even in the face of these massive capital requirements. In order to counter the significant earnings attrition and cash flow deficit that the Company is experiencing and will continue to see without ameliorative rate relief, this application requests that the Commission approve important compensating cost-recovery mechanisms, including the inclusion in rate base of specific post-test year plant in which the Company had already invested before the end of the Test Year, and an attrition adjustment that provides for sales and expense growth through 2010, the first full year that new rates from this case would be in place.

Because part of APS's significant attrition has been and continues to be caused by customer growth, this application also presents the Commission with the opportunity to reduce the impact of the attrition component of the Company's total revenue requirement deficiency on existing customers by approving an impact fee charged to new applicants for electric service, as Mr. Rumolo describes in detail in his testimony.

Finally, APS requests that the Commission recognize the vital importance of restoring the Company's financial health, not just in the short run but for the long term, so that APS has the financial means necessary to invest in the

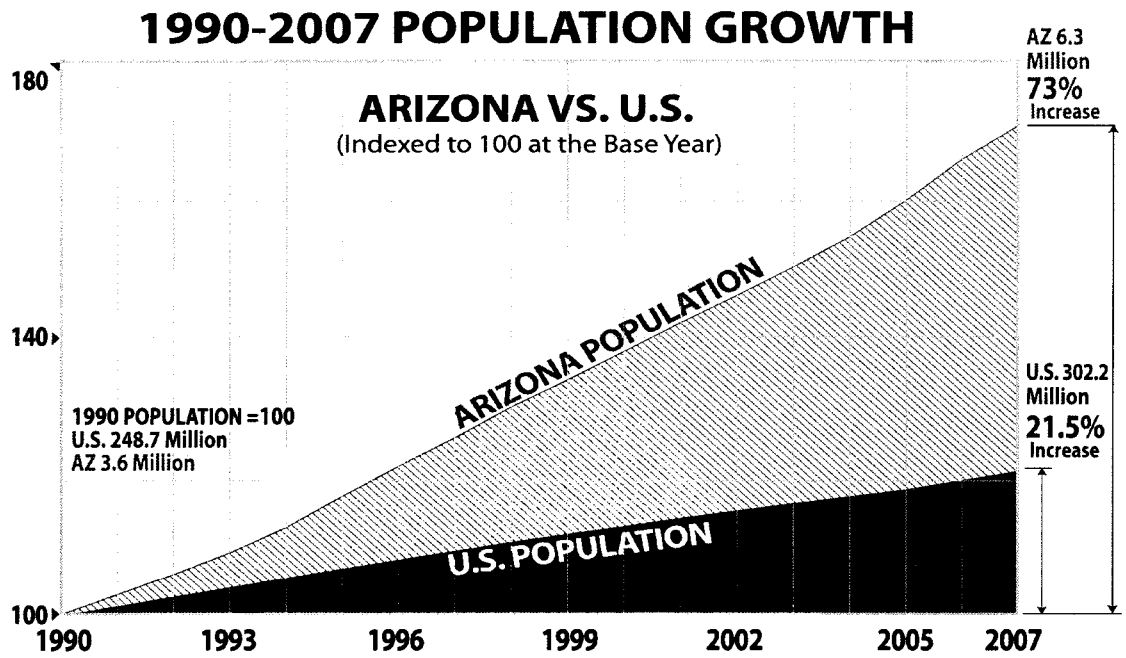
infrastructure necessary to energize Arizona. To that end, in addition to the Company's revenue request, APS asks that the Commission use this proceeding as a context for devising a long-term plan that will ultimately restore APS's financial health and allow it to recover its formerly held high BBB (i.e., BBB+, if not A-) credit rating status within the next several years, including a post-order proceeding to be conducted the year after rates from this case are set to ensure both that APS has the opportunity to earn its authorized rate of return and a reasonable return on Fair Value, and that it is on target for long-term financial stability and improvement.

V. THE IMPACT OF GROWTH

A. Growth in the APS Service Territory

Q. PLEASE DESCRIBE THE GROWTH IN APS'S SERVICE TERRITORY.

A. APS operates in a remarkable and challenging growth environment. Arizona's population has been one of the five fastest growing in the United States for the past 70 years, and APS is the State's largest electric utility. The population growth rate in Arizona ranked second in the nation in 2007, and has jumped by roughly 23% since the 2000 population census (compared to a national growth rate of just over 7% during that time). As the following graph demonstrates, from 1990 to 2007, Arizona's population increased more than three times faster than the national average.



Graph DEB-1

While the recent downturn in the residential housing market has caused the striking growth rate that Arizona experienced over the past decade to slow, growth continues nonetheless. APS's 2007 customer growth rate was over two percent. Even in the midst of what many economists now believe is an economic recession, there is no evidence that the growth rate will decelerate to any significant degree in the long term. APS recognizes that its growth projections will continue to change with the economy in the short-term, but the long-term outlook remains stable.

B. The Company's Capital Spending Requirements

Q. WHAT ARE THE COMPANY'S CAPITAL SPENDING REQUIREMENTS OVER THE NEXT THREE YEARS?

A. The capital spending required of APS to meet its growing demand and maintain its existing system is nothing short of extraordinary, amounting to one billion dollars per year on average for the foreseeable future. These expenditures are

essential to the Company's business. Some are required by environmental laws. The others are required so that APS can meet its obligation to serve Arizona's existing and future customers, and do so reliably and effectively. As described below, the Company has carefully scrutinized its budget to ensure that it is not spending any more than it needs to in order to meet its growing demand and improve its existing system so that it can continue providing reliable energy to its growing customer base. While some costs can be and have been cut or deferred, the Company cannot escape the harsh reality that it will have to spend three billion dollars over the next three years to pay for capital projects.

Many of these cost pressures are not unique to APS. To the contrary, capital spending and related financial strains plague the electric industry as a whole, causing the price of electricity to go up nationwide. A recent article published by Electric Perspectives, "Behind the Rise in Prices" attached hereto at Attachment DEB-1, describes the recent nationwide rise in the price of electricity and the reasons for that increase, including increased capital spending needs in each of the three segments of the electric system (generation, transmission, and distribution). As that article indicates, the industry's capital spending on distribution infrastructure alone increased by 19% from 2000 to 2004—a level of distribution investment that is expected to continue and grow, and which is necessary both to meet new customer growth and to maintain increased system reliability for the future.

A second study prepared by The Brattle Group, "Transforming America's Power Industry: The Investment Challenge," attached hereto at Attachment DEB-2, also highlights the industry's capital spending challenges. As that study indicates, the power industry will be required to invest on the order of $1.5

trillion over the 2010 to 2030 time period, $675 billion of which is caused by distribution-related spending alone. *See* DEB-2. According to the Brattle Group, the major drivers of these cost increases include rising commodity prices, rising utility infrastructure costs, and the imposition of higher renewable standards – all factors that have greatly impacted the rise in APS's non-fuel costs that have necessitated this rate request. *See* DEB-2.

Importantly, the spending requirements facing the industry in general are exacerbated in high-growth areas of the country like Arizona, which requires investment in more new infrastructure to meet increasing electric demand compared to the nation's low-growth areas. According to a May 2008 study sponsored by the Arizona Investment Council and prepared by the L. William Seidman Research Institute at Arizona State University entitled "Infrastructure Needs and Funding Alternatives for Arizona: 2008-2032," electricity demand from Arizona's growing population will increase by about 85% between now and 2032, resulting in a total required capital investment in energy infrastructure of between $74 billion and $86.5 billion, depending upon the mix of generation technologies employed going forward. According to the study, the state's current funding for electricity is insufficient, and continued funding for the energy sector at the status quo will result in a funding deficit of **$109 billion**.

In other words, APS shares with other utilities many of the cost pressures that have caused electric rates to rise across the country (including the already significant investment necessary to maintain its existing system and to meet increasing environmental requirements), but has the extra burden of shouldering the additional costs required because of APS's position as the largest utility in the second fastest growing state in the nation.

Q. PLEASE DESCRIBE THE PROJECTS THAT APS IS REQUIRED TO UNDERTAKE OVER THE NEXT SEVERAL YEARS TO KEEP UP WITH GROWTH AND TO RELIABLY SERVE THE COMPANY'S GROWING CUSTOMER BASE.

A. Attached hereto as Attachment DEB-3 is a summary of the specific projects that APS must undertake over the next several years in order to fulfill its duty to serve. As that attachment shows, the next three years will require the addition of a significant number of new substations, transformers, feeders and meters; numerous miles of lines and cable; and numerous miles of rights of way, among a myriad of other items. In addition, to comply with various environmental laws, APS is required to spend more money on environmental projects (such as the significant environmental projects at Cholla Generating Station, described by APS Witness Daniel Kearns in his testimony) than it has in the past, further exacerbating APS's capital expenditure needs. And those environmental-related costs will only grow as new state and federal laws are passed that require further environmental compliance upgrades to APS's existing system.

Q. CAN THE COMPANY REDUCE ITS CAPITAL SPENDING REQUIREMENTS BY SIMPLY REFUSING TO CONNECT NEW CUSTOMERS?

A. No, it cannot. Electricity is a necessary commodity in our modern and increasingly energized society—almost as important to Arizonans as air and water – and APS has a legal duty to supply electric service to every person in its service territory. Even if a competitor sought to provide electric service within APS's service area, the Company would still be obligated to serve any customer who rejected that competitor in favor of APS or whom the competitor failed or refused to serve, and would still have to construct the requisite distribution facilities in order to transmit or "wheel" any chosen competitor's energy to its

customer. In fact, at the same time the Commission began the process of introducing retail competition to Arizona in the late 1990s, it ensured that universal electric service coverage would continue throughout the State by designating APS as the "provider of last resort" in its service territory and requiring the Company to continue its low income assistance programs. *See* Decision Nos. 61973 (October 6, 1999) and 67744 (April 7, 2005).

As a result, APS must anticipate and plan for all growth in customers and electric demand that will occur in its service territory in the foreseeable future and invest in the infrastructure necessary to serve that increasing load growth (which planning and investment occurs well before the infrastructure must be ready to operate). This is true irrespective of whether the margin of revenue the Company receives from these new customers is sufficient to cover the additional costs required to serve those customers.

Q. **CAN THE COMPANY MEANINGFULLY OFFSET ITS CAPITAL SPENDING NEEDS BY CUTTING OTHER COSTS?**

A. No, it cannot. The non-discretionary nature of APS's spending goes well beyond just its infrastructure requirements (which alone comprise more than a third of the Company's total revenue requirement). The vast majority of APS's overall spending is mandatory, including such items as income taxes, property taxes, fuel costs and O&M expenses. Of those, only O&M – which makes up less than one-quarter of APS's revenue requirement—leaves any room for potential flexibility, and virtually all of such costs are required, such as the cost of payroll and employee benefits (medical insurance), payroll taxes, distribution facilities maintenance, and power plant maintenance. Although, as I will describe in detail below, APS has done its part to contain its costs, the Company

cannot offset the impact of its growing capital spending needs to any significant degree by cutting costs without detrimentally impacting service reliability and business operations.

Importantly, while most of APS's costs are largely outside of either the Company's or the Commission's control, the Commission can influence an important cost that substantially impacts APS's cost of service: the cost of debt capital (that is, the interest rate the Company is paying on all of its debt, such as loans and bonds). Such costs—which increase with APS's capital spending—are entirely dependent on the financial strength of the Company. The healthier APS is financially, the better are APS's capital costs, and the lower the price of electricity for APS customers.

Q. IF THE COMPANY'S CUSTOMER GROWTH RATE SLOWS, WILL THE CAPITAL SPENDING REQUIREMENTS DESCRIBED IN THIS APPLICATION DECREASE SUBSTANTIALLY?

A. No, they will not. Because the Company must build most of the infrastructure it will need to support customer growth well in advance of its arrival, a temporary slowdown in customer growth from assumed levels will not immediately reduce by a significant amount the costs that the Company is required to incur in the short term to meet the anticipated demand. Due to the long lead times on some equipment and projects, the Company has already incurred many of the infrastructure costs required to meet the anticipated load growth over the next few years. This remains true irrespective of any short term change in the customer growth rate (which tends to be cyclical and will rise again in any event, as Mr. Ewen explains).

Additionally, as I previously described, the Company's capital spending requirements include sizable amounts that are not directly affected by any slowdown in incremental customer growth. Examples of this include power plant repair and replacement projects intended to provide for their reliable and safe operation, including large environmental projects; capitalized nuclear fuel costs; and projects required to maintain the reliability of the distribution system. Because the cost of the materials necessary for these construction projects has increased substantially compared to historical periods (as described in the Brattle Group study attached at DEB-2 and as I will discuss in detail later in my testimony), any cost-reductions that might result from a significant slowdown in customer growth will be offset by these other cost increases that drive the Company's capital spending requirements upward.

Q. DOES THE COMPANY'S RATE REQUEST INCLUDE ANY ITEMS THAT ARE NOT WITHIN THIS COMMISSION'S REGULATORY JURISDICTION?

A. No. The Company has been careful to include in its rate request only those items that fall within the Commission's regulatory jurisdiction. In other words, the Company's requested revenue requirement increase does not include its substantial transmission projects, for which APS is seeking timely recovery from the FERC as APS was encouraged to do in the Company's last rate proceeding.

C. The Company's Rates Are Non-Compensatory

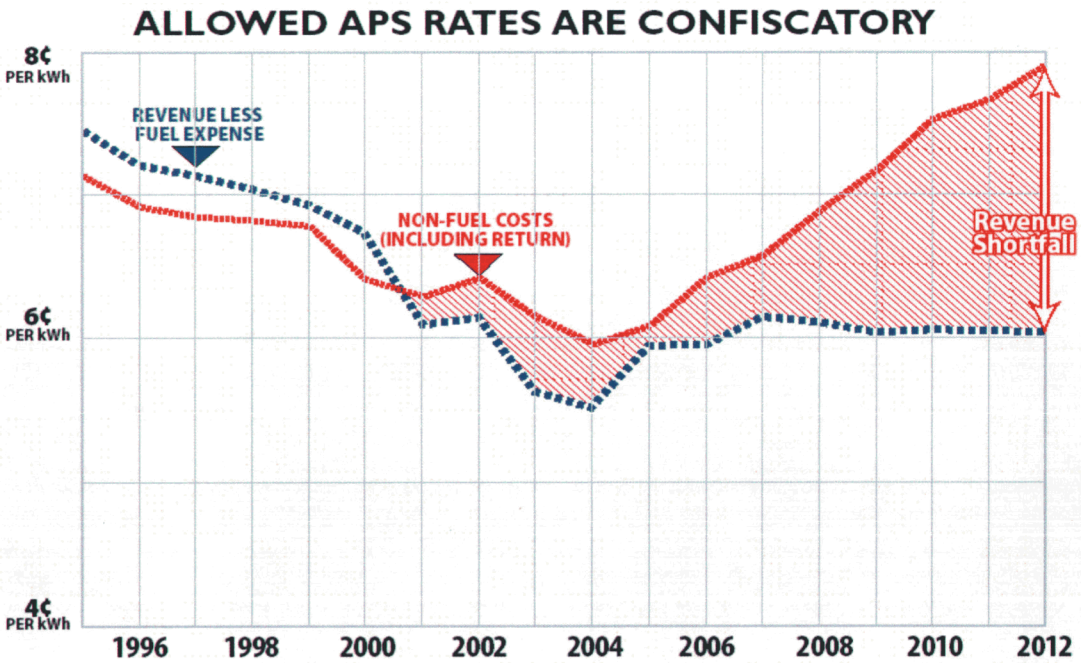
Q. WHEN IS A RATE "COMPENSATORY"?

A. Generally speaking, a utility's rates are compensatory (that is, they adequately pay the utility for providing electricity to the community) if they, in combination with the utility's other charges, generate sufficient revenue to meet the utility's

operating and capital costs and give the utility a reasonable rate of return on the fair value of its property. As described in the Company's application, constitutional principles of rate regulation require that the Company must have the opportunity to earn a reasonable rate of return on the fair value of its property at the time new rates become effective. It is a fundamental principle of utility regulation that a rate that does not give the Company this opportunity results in confiscation of the Company's property, and is not a just and reasonable rate.

Q. DO THE RATES THAT APS CURRENTLY CHARGES COMPENSATE THE COMPANY FOR ITS CAPITAL AND OPERATING COSTS?

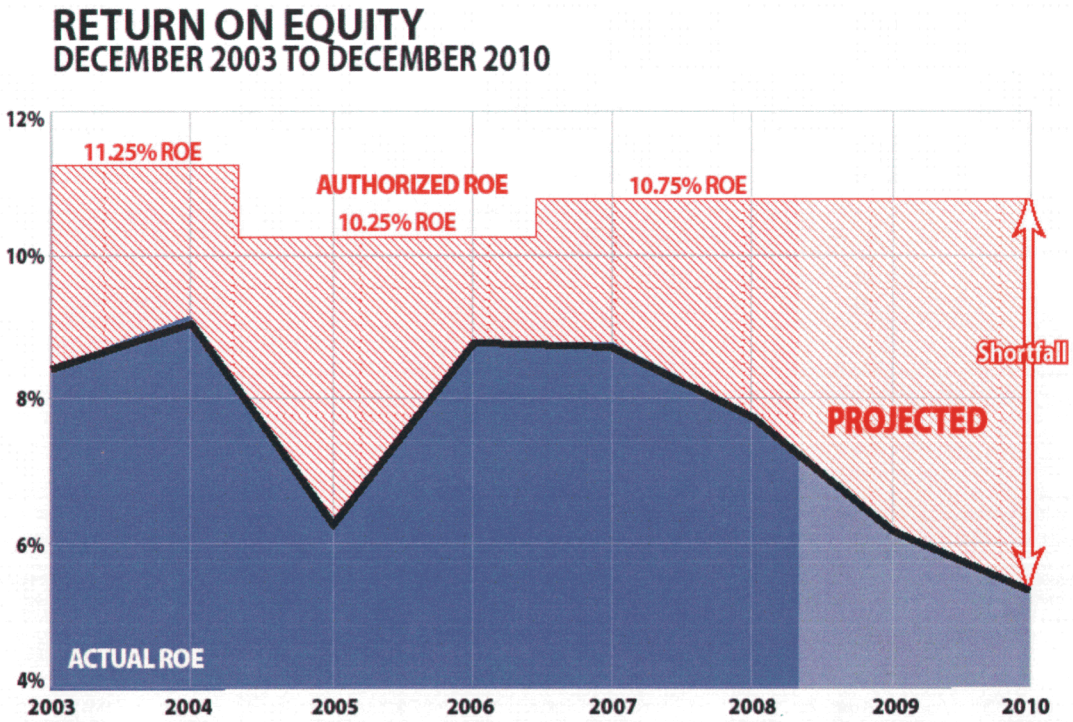
A. The answer to this question is an emphatic "no." The non-compensatory nature of APS's current rates is easily demonstrated by comparing the Company's Revenue Net of Fuel (or Gross Margin) per kilowatt-hour ("kWh") to its non-fuel costs per kWh. This analysis shows that the Company's rising sales and increasing customers are not producing sufficient margins to support the Company's increasing capital costs and inflating operating costs, let alone providing the Company with the opportunity to earn anywhere near a reasonable rate of return on its investment. In other words, "growth does not pay for itself." As the following demonstrates, the Company's rates do not give the Company a sufficient margin to cover the inflationary impacts of APS's capital and operating costs to serve existing and future customers.



Graph DEB-2

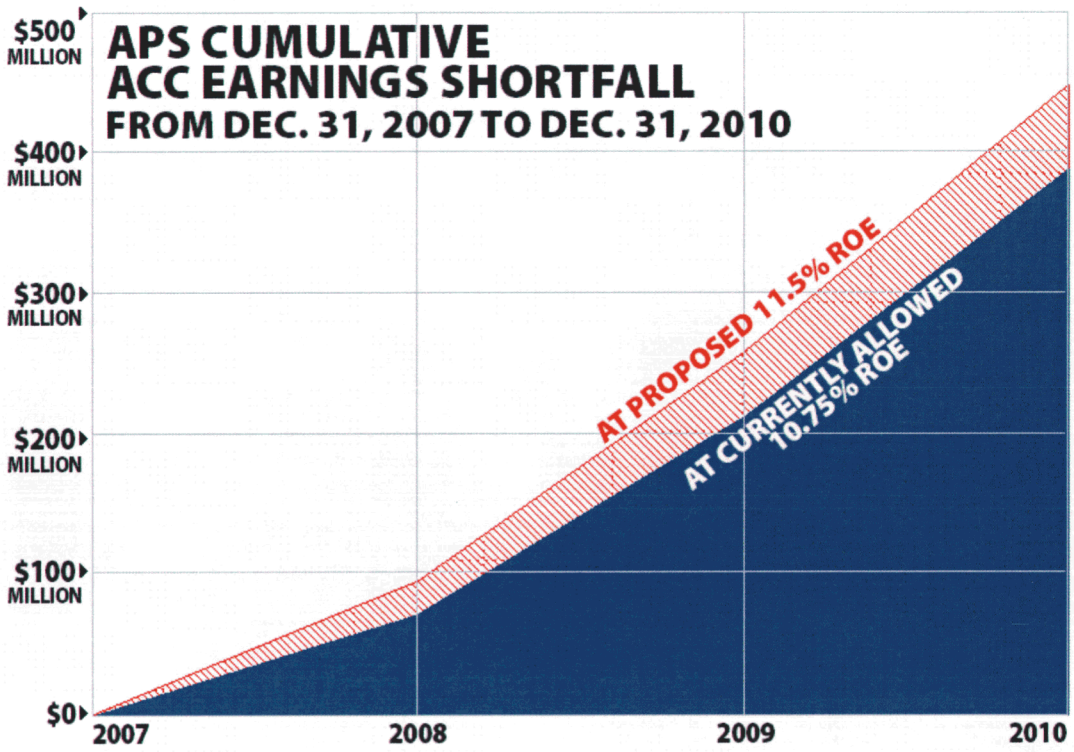
As this graph shows, APS's rising costs are significantly higher than the Revenues Net of Fuel that the Company receives from rates, and are rising at a faster pace than non-fuel revenues. APS is thus required to invest increasing capital dollars to support new and existing customers at a time when its revenue increases have not been strong enough to provide the cash flow needed to both support its operational expenses and still fund its massive capital spending needs.

The confiscatory nature of APS's rates has caused the Company to experience severe attrition. Indeed, as the following graph makes plain, APS has not earned anywhere near its authorized rate of return in the last five years, resulting in a total Company cumulative earnings shortfall of **$321 million** between 2003 and 2007.



Graph DEB-3

The Company does not seek to recover its historical loss of earnings in this rate case. But the Company's earnings shortfall continues to climb under the current rate structure, as the following graph depicts, and APS could lose another **$384 to $454 million** of earnings between now and 2010 if the Commission does not provide adequate rate relief—a number that again includes only those cost of service items that fall within the Commission's regulatory jurisdiction.



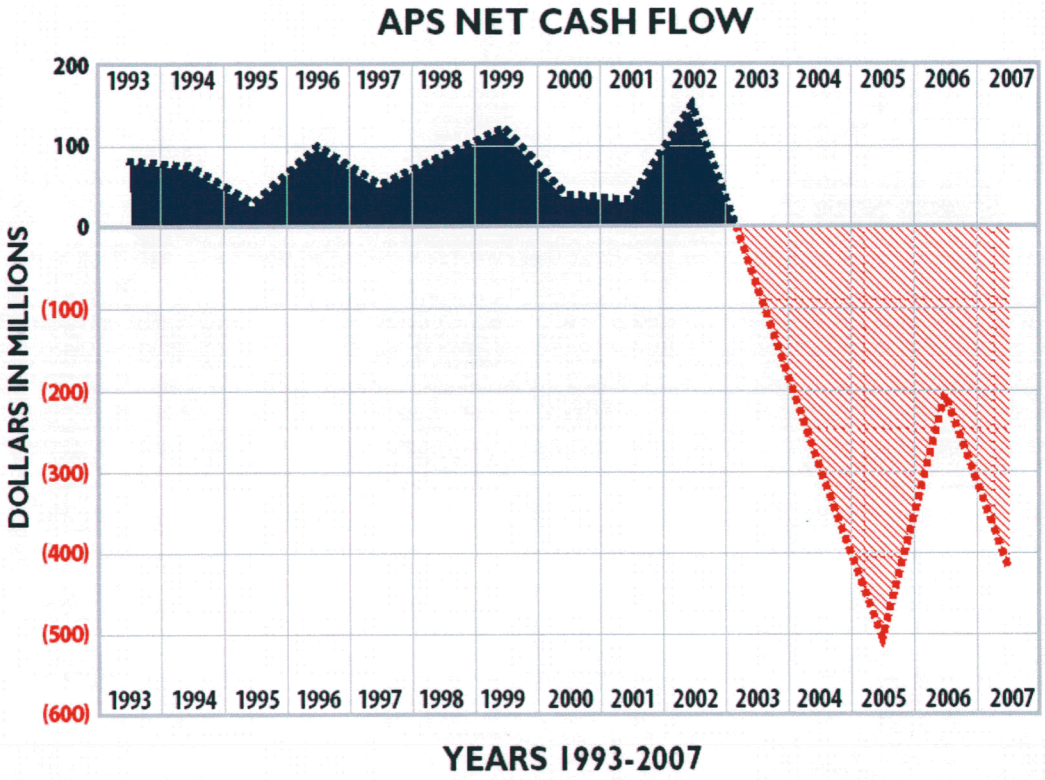
Graph DEB-4

As the foregoing makes plain, APS suffers significant earnings attrition—a trend that will both continue and compound without adequate rate relief, with detrimental impacts to the Company and its customers.

Q. HOW ELSE MIGHT YOU DESCRIBE THE FINANCIAL PROBLEM FACING THE COMPANY?

A. Another way to look at the Company's financial crisis is to examine the issue in terms of net cash flow, after accounting for capital expenditures and financing costs. Net cash flow after capital expenditures and financing costs is a measure of a company's financial health, and compares its cash receipts to its cash payments over a certain period of time. The following graph, which depicts

APS's net cash flow after capital expenditures and financing costs from 1993 to the end of 2007, paints a compelling picture of how far APS's financial vitality has weakened over just the past five years.



Graph DEB-5

As this graph depicts, for at least the 10 years preceding 2003, APS was able to limit its cash expenditures to the amount of cash the Company took in, resulting in positive net cash flow and a financially strong utility. From a state and local government perspective, one would refer to this situation as a "budget surplus" condition. In 2003, however, that trend reversed, and the Company's required cash outlays began to exceed its cash receipts by significant amounts – a negative cash flow that has resulted in weakening credit metrics and declining financial health (a "budget deficit" condition). Indeed, even considering the rate increase authorized in Decision No. 69663, APS still experienced a 2007

"budget deficit" in the amount of **$422 million**. Without adequate rate relief, APS will be forced either to forego required expenditures at the threat of weakening service reliability, or continue its path of massive deficit spending to the further detriment of the Company's financial health and ability to invest in the infrastructure necessary to energize Arizona's growing population at reasonable costs.

D. APS's Deteriorating Financial Health

Q. GIVEN THE NON-COMPENSATORY NATURE OF APS'S RATES, WHAT IS THE COMPANY'S CURRENT FINANCIAL CONDITION?

A. As it has been for the past several years, APS is in serious financial jeopardy. The revenue shortfall described above, caused by the combination of extraordinary capital spending requirements and inadequate rates, has deleterious effects on both the Company's earnings and Pinnacle West's stock performance. APS's return on its capital investment is steadily and significantly declining—a situation that negatively impacts APS customers and that will not change without timely and decisive action from this Commission.

As described in detail in the testimony of Dr. Avera, the authorized ROE approved in the Company's last rate case is too low to compensate the Company's investors for their risk. Dr. Avera's expert analysis concludes that a more reasonable ROE is in the range of 11.25% to 12.50%. APS seeks an ROE of 11.5%, decidedly on the low end of Dr. Avera's range. As of the end of the Test Year, APS's ACC-jurisdictional ROE (when normalized for weather) stood at a mere 8.6%. Without relief, that number drops to 6.3% by 2009 and 5.4% by 2010.

Q. DO THE COMMISSION'S TRADITIONAL RATE-MAKING PRACTICES ALLOW THE COMPANY TO EVER RECOVER THE MILLIONS OF DOLLARS THAT APS HAS LOST BECAUSE OF ATTRITION?

A. No. In APS's remarkable capital expenditure environment (one requiring capital expenditures of one billion dollars per year for the next three years), a policy that couples significant regulatory lag with the use of an historical test year in setting rates causes APS to be unable to recover the millions of dollars it has already lost because of attrition, and will ensure that attrition continues. This policy is inherently confiscatory and is directly contrary to the constitutional requirements that govern the Commission's rate-making authority.

Q. PLEASE EXPLAIN YOUR PREVIOUS ANSWER.

A. Under the current rate-setting model, the Commission generally evaluates APS's cost of service for a historical twelve-month period and uses that "test year" (subject to various pro forma adjustments) as a guide to determining APS's future revenue requirement. **In other words, the Commission sets APS's future rates by looking backwards**. Although everyone generally acknowledges that APS's costs and revenues will have increased since the test year, the unstated (and unproven) assumption is that they have increased proportionately, such that APS's earned return on investment will not fall below allowed levels. However, this assumption is demonstrably false. Coupled with a regulatory lag of up to 18 months to two years between the end of the test year and the time rates become effective, the historical data used in setting the Company's rates is inevitably stale and unrepresentative of conditions that will exist when the new rates are effective. Earnings attrition naturally results from this rate-making model any time that costs rise faster than revenues after the end

of the historic test year.

While the traditional rate-setting practice may produce relatively stable returns during periods when APS's per kilowatt hour cost of service does not change significantly from one year to the next, it is inherently confiscatory during times, like these, when APS's annual cost of service will be markedly higher than its annual revenues by the time the new rates go into effect than it was during the Test Year (higher even than it was when APS first filed its rate case). In APS's current and projected capital spending environment, this rate-setting methodology will, on its own, **never** produce rates that will allow APS to both recover its costs and earn its approved rate of return. In these conditions, the rates are non-compensatory the very moment that they are set. Attrition will, and has, set in—a condition that creates intense earnings pressure on the Company, reduces the capital available for payment of debt obligations, and discourages capital investment in the Company from participants in the debt and equity markets.

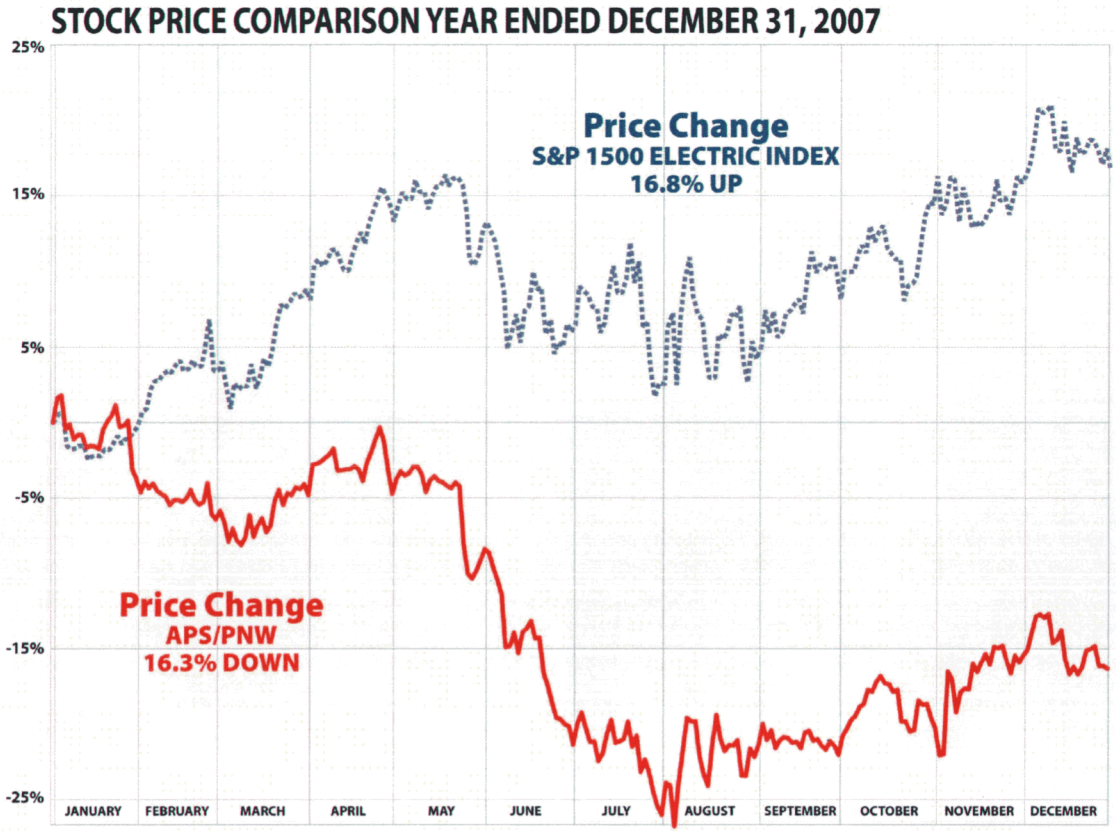
For this reason, the Commission cannot reasonably adopt the view expressed in Decision No. 69663 that attrition "is not, in and of itself, particularly significant" because it serves as little more than the "trigger mechanism for a utility" to determine when the next rate case should be filed. While this theory may apply when the Company's costs and revenues are more in sync from one year to the next, it is simply wrong and, frankly, confiscatory under present conditions. Attrition will occur immediately, and, indeed, will have already occurred during the course of the rate proceeding itself. Thus, the "trigger mechanism" will instantly deploy, justifying another rate filing literally the moment the new rate order is entered. The result is a constant string of rate

cases (to the detriment not only of the Company, but of the Commission and customers). And, under the strict historical test year model, no future rate order will allow the Company to recover the earnings lost because of attrition between the time of one rate order and the next. In these circumstances, the Commission's failure to address this phenomenon—that is, the earnings and ROE attrition caused by costs that outpace revenues after the Test Year but prior to a final order—necessarily produces rates that are not just and reasonable at the time they are set.

Q. WHAT IMPACT DOES THE COMPANY'S HIGH LEVEL OF UNDEREARNING HAVE ON APS AND ITS CUSTOMERS?

A. The unremitting earnings shortfall that results from the current regulatory model in APS's staggering growth environment has a detrimental effect on the Company's overall financial integrity and Pinnacle West's stock value, and adversely impacts APS's ability to finance the construction programs and improvements necessary to meet the demands of growth—a negative impact that will inevitably inure to the detriment of APS's customers.

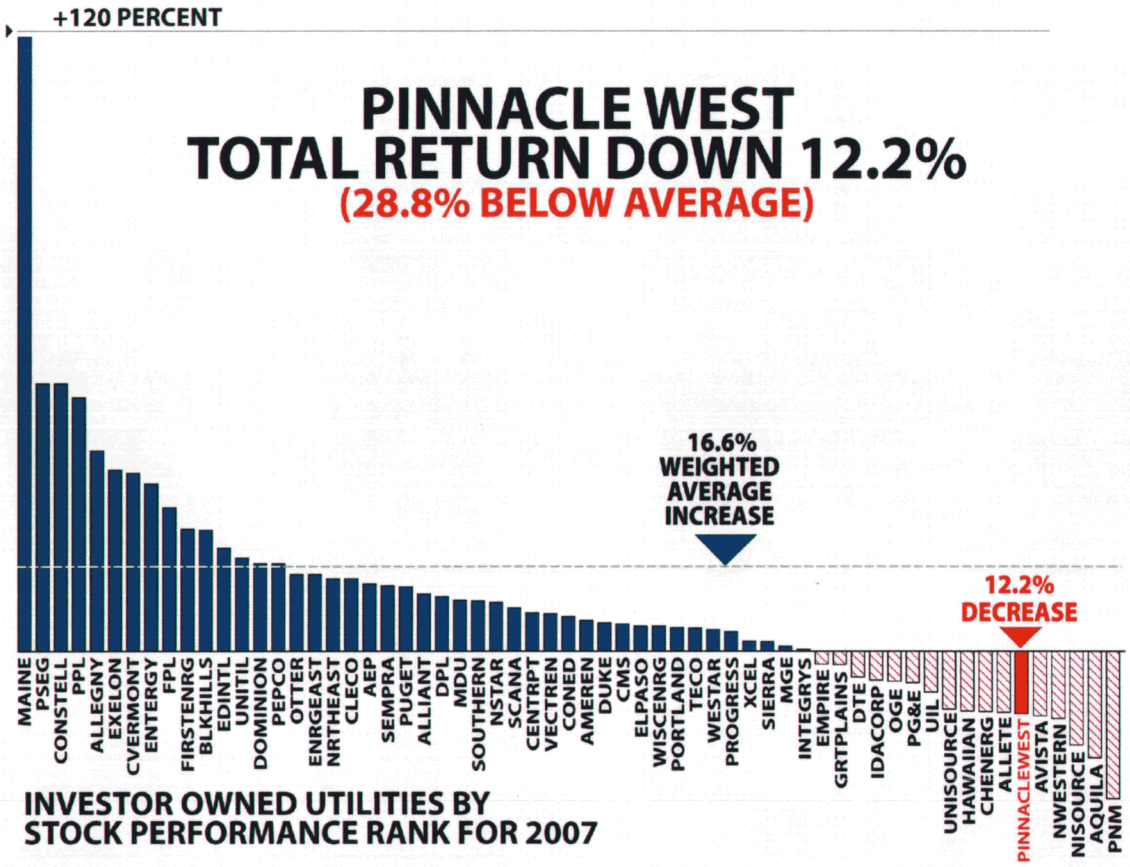
There is no doubt that APS's declining ROE has caused Pinnacle West's stock to perform significantly worse than that of other electric utilities. Consider the following graph, which compares Pinnacle West's stock performance against that of the Standard & Poors ("S&P") 1500 Electric Utilities industry-specific index:



Graph DEB-6

This graph shows in no uncertain terms that Pinnacle West stock performs far worse than the industry average, almost certainly because of APS's perilous financial health. Indeed, as illustrated above, while the stock value of the S&P 1500 Electric Utilities ***increased*** by 16.8% from December 31, 2006 to December 31, 2007, Pinnacle West's stock price has, in contrast, significantly ***decreased***, falling by 16.3% during that period. And it has fallen even further since, declining by *another* 20% between December 31, 2007 and April 30, 2008 – the **second worst** performing stock of the investor-owned utilities ranked in the S&P electric utility index. In fact, as shown in the following illustration, Pinnacle West's stock was the sixth ***worst*** performing stock of the 61 investor-owned electric utilities ranked by the Edison Electric Institute stock index for

2007 in terms of Total Return (a calculation that includes both the change in stock price and the value of any reinvested dividends).



Graph DEB-7

This trend is not unique to 2007. A comparative analysis of electric utility stock performance for utilities in the S&P electric utility index during the twelve months ended April 30, 2008 places APS **dead last**, showing an APS stock price drop of **30.4%** compared to an industry average decline of just 2.1%.

Q. DOES PINNACLE WEST'S UNDERPERFORMING STOCK IMPACT APS AND ITS CUSTOMERS?

A. A low trading stock price clearly hurts both APS and Pinnacle West's investors (who are not just big businesses, but average individuals whose retirement

portfolios and those of their retirement funds include utility stocks). But a low-selling stock also evidences a financial condition that has negative impacts on APS customers, who depend upon the health of their utility so that they may continue to receive reliable service at reasonable prices.

To secure financing on reasonable terms, APS is required to maintain a certain debt to equity balance. If APS earns too low a return on equity, it will be difficult for the Company to attract new equity investors. It is important to understand that APS competes for investors in the money market with each of the other investor-owned electric utilities nationwide – not just those in Arizona. If an investor seeks to invest in a utility, it will naturally choose one with a high return commensurate with the investment risk. Significantly, the return that investor will receive does not just come in the form of a dividend, but in the value of that investor's stock. Naturally, investors will gravitate towards utilities whose stock outperforms others in the industry. By that measure, investors have little incentive to invest in APS if—in just one year—their stock value will have dropped by 30% (as it did during the twelve months ending April 30, 2008, making APS's stock the **worst** performing during that period). Assuming the investor invested $10,000 in 250 shares of APS stock on May 1, 2007, he will have lost $3,000 in just one year. Even if that investor received a hypothetical $2.00 per share dividend that year, he still has an overall **loss** of $2,500—a loss that would not have occurred had he invested in any of the many utilities whose stocks perform far better than does APS's.

If APS cannot attract equity investment, the Company is left with one of three choices: finance through the debt markets (if any credit ratings headroom exists to do so)), sell shares at lower prices (thus requiring the Company to issue more

shares to generate the same level of equity, thus diluting the value of each investor's holdings and making the stock even less attractive), or cancel the project. Once the stock sells for so low a price that issuing equity is a near impossibility, APS will not be able to achieve its debt/equity balance and will either have to sacrifice the completion of increasingly unaffordable (but still necessary) construction projects, or complete those projects only through extraordinarily higher financing costs. In each case, the customer suffers: either because necessary projects are foregone or delayed for lack of financing (with the attendant impact on future service reliability) or because the Company's cost of service—and thus the rates it must charge—will increase commensurate with the increase in financing costs.

Q. DOES THE COMPANY'S EARNINGS SHORTFALL HAVE ANY OTHER IMPACT ON THE COMPANY AND ITS CUSTOMERS?

A. Unfortunately, yes—a significant and potentially debilitating one. APS's inability to earn anywhere near the Company's allowed rate of return—let alone the 11.5% ROE that the Company should be allowed—places APS's credit ratings in continued peril. As I described at length in APS's last rate case, the Company's earnings shortfall has a significant impact on the Company's credit metrics. In fact, as shown in the testimony of Mr. Kearns, APS believes that without timely relief from this Commission, the Company's credit metrics will reach non-investment grade by the end of 2009, which could result in a credit downgrade with devastating financial results to both APS and its customers.

Q. WHAT CRITERIA DO CREDIT RATING AGENCIES USE TO ASSESS A UTILITY'S CREDITWORTHINESS?

A. Credit rating agencies assess a utility's creditworthiness based on several qualitative and quantitative factors, as described in detail in Attachment DEB-4. As a general matter, credit rating agencies assess the credit strength of a utility by examining the magnitude of its operating cash flows ("funds from operation" or "FFO") relative to its interest expense and total debt. The size of operating cash flows relative to a company's total debt (its "FFO/Debt ratio") indicates the flexibility that company has to withstand unexpected financial difficulties. If a utility's operating costs increase faster than its revenues, operating cash flows decline and its FFO/Debt ratio weakens. This condition places the utility's credit rating in jeopardy.

If a utility's regulatory environment does not appear sufficiently responsive to the company's financial condition and financial performance, particularly in the face of high capital spending requirements, the utility's credit rating further suffers. As Moody's Investors Service ("Moody's")—a national credit rating agency—has recently stated in a special comment on the electric utility sector:

> One of the most significant factors incorporated into our outlook is a view that most utility management teams will maintain healthy and constructive relationships with their state regulatory authorities and that most state regulatory authorities prefer to regulate financially healthy utilities within their states.
>
> However, there are concerns arising from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory relief, which in turn can increase the likelihood for political and/or regulatory intervention. Conceivably, the combination of rising costs, higher infrastructure investment needs and larger or more

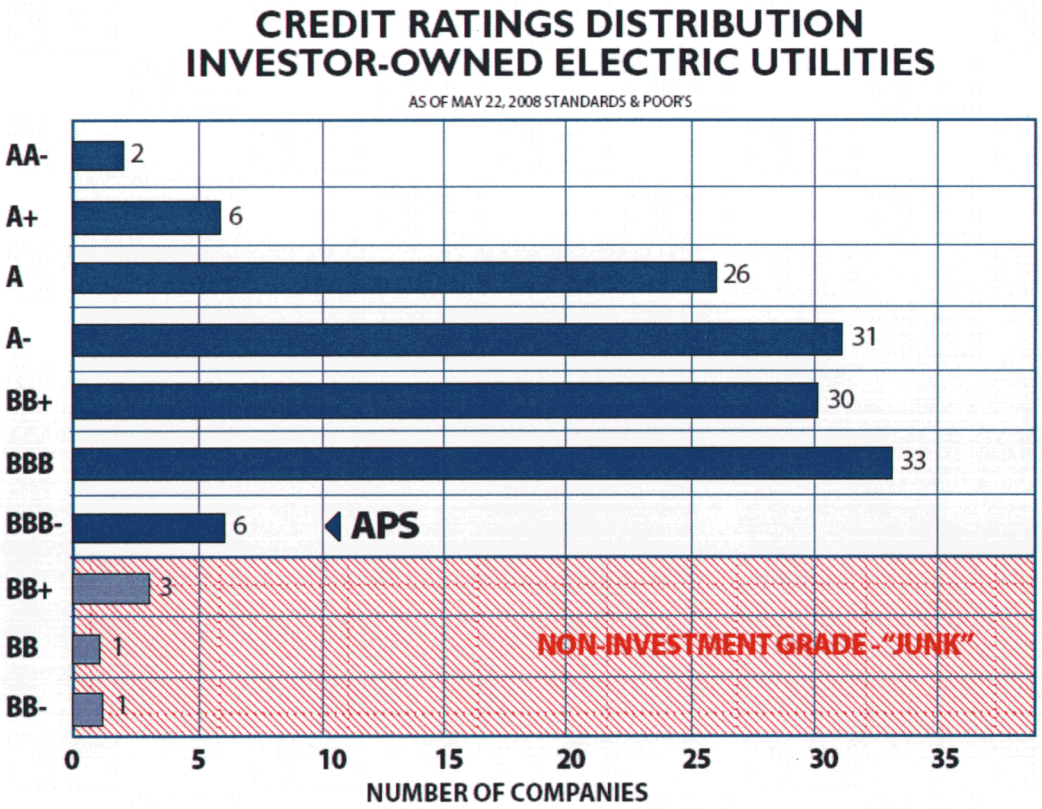
> frequent requests for rate relief could create pressure for future incremental relief from state regulators, or at a minimum, raise the uncertainty level associated with expected recoveries—thereby directly affecting one of our primary rating drivers. . . .
>
> Moody's will continue to assess the constructiveness of the regulatory relationships between utility companies and their respective regulatory commissioners. **In our opinion, the relationships with regulators could conceivably counterbalance any potential deterioration of key financial credit ratios, especially if the deterioration is expected to be relatively temporary. If, however, the business and operating risks for a utility appear to be increasing at a more significant pace, or the regulatory relationships appear to take a more adversarial tone, the rating outlook would likely change, even if the key financial credit ratios were maintained at current levels.**[1]

There can thus be little doubt that ratings agencies will closely and carefully assess the extent of regulatory support and the consistency of treatment that will be provided to the Company in this proceeding.

Q. WHAT IS THE CURRENT STATUS OF APS'S CREDIT RATINGS?

A. APS's credit ratings on its outstanding debt are currently on the lowest rungs of the investment grade credit ladder ("BBB-" by S&P, BBB by Fitch Ratings ("Fitch"), and "Baa2" by Moody's). As the following depicts, APS's current credit ratings are among the worst of the investor-owned electric utilities in the industry. In fact, APS is pretty much at the bottom of the barrel. Of the 139 rated utilities, only five companies are rated lower than APS.

[1] Moody's Investor Service Special Comment, Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector, August 2007.



Graph DEB-8

And with APS's growing attrition, its financial credit metrics are sliding into junk grade range. As described in detail by Mr. Kearns, assuming the Company decides and is able to issue $400 million of common equity during 2008, the Company should be able to keep its FFO/Debt ratio within the 18% to 28% BBB range set by S&P for the remainder of this year, but that ratio will fall below the 18% FFO/Debt threshold for non-investment grade to 17.6% at the end of 2009 and 16.6% at the end of 2010, respectively, absent rate relief. These estimates are based on the very same financial forecasting methodology that APS uses in the ordinary course of business and in regular dealings with ratings agencies and financial analysts.

Because the current historical test year regulatory model produces significant attrition under the current circumstances, and thus decreases the Company's operating cash flow and earnings, by its very nature it detrimentally impacts APS's credit metrics—particularly in APS's capital spending environment. Consequently, APS's credit ratings are in continued jeopardy, especially if the Company does not receive timely and supportive regulatory treatment. Although a fall to junk grade has been forestalled to date by several factors, including the increased cash-flow from the forward-looking PSA approved in Decision No. 69663, a modest increase in income during the third quarter of 2007 resulting from abnormal summer weather, a non-recurring tax benefit and the potential for increased cash flow from Schedule 3 proceeds, **APS firmly believes that, absent timely relief from this Commission, a further downgrade is inevitable**.

Indeed, each of the nationally recognized statistical rating organizations that rate APS's debt—S&P, Moody's, and Fitch—as well as various financial analysts have recently noted the significant danger to downgrade presently threatening APS. A common theme among such organizations is that Arizona presents what they believe is a "challenging regulatory environment" and that the combination of the historical test year regulatory model, regulatory lag, and APS's huge capital expenditure requirements cause "severely exacerbated" attrition that results in "chronic underearning" for the Company.

Immediately following the Commission's decision in the last rate case, for example, S&P reported that "[t]he use of a historical test year, combined with the tendency for utility rate cases to take an extended period of time to resolve in Arizona, is expected to constrain the company's ability to earn its authorized

ROE, with earned ROE likely to remain in the single digits over at least the next several years." In fact, while S&P maintained its BBB- credit rating for APS (the final notch above "non-investment" grade) after entry of Decision No. 69663, it noted its conclusion that APS's regulatory dynamics are "complex and challenging" and predicted that "**[r]atings could be lowered to speculative [non-investment] grade if the company is not able to overcome the challenge of managing high capital expenditures and associated regulatory recovery.**"[2]

After entry of the last rate decision, Moody's affirmed its negative outlook on APS and Pinnacle West, opining that "based on the time that it has recently taken to conclude APS's general rate cases (the June 2003 case was concluded in April 2005; the then current case was initially filed in November 2005), we believe there remains a significant risk that credit metrics will weaken over the medium term due to the continued lag in recovery of non-fuel related costs."[3] Recently, on December 17, 2007, Moody's reiterated this position, specifically citing "APS's continued need for rate increases in a regulatory arena that has historically been challenging." Moody's ultimately confirmed that "**[g]iven APS's current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating.**"

---

[2] Standard & Poor's Research Update: Pinnacle West Capital Corp., Arizona Public Service Co's 'BBB-' Rating Affirmed, June 28, 2007 (emphasis added).

[3] Issuer Comment: Arizona Public Service Company, June 21, 2007 (emphasis added).

In a recent update, Fitch, downgraded APS's commercial paper and characterized the Commission's rejection of an attrition adjustment in Decision No. 69663 as a "negative development in light of the utility's 2007-2009 capital requirements," specifically opining that "**earnings and cash flow attrition due to regulatory lag and/or unanticipated disallowances is a significant challenge to the sustainability of PNW and APS's investment grade credit ratings. Revenue increases below our expectations or undue delay would likely result in credit rating downgrades**."

Plainly, each of these three nationally recognized credit rating agencies have serious concerns about APS's weak credit metrics and realize that only significant and timely rate relief for non-fuel costs will allow APS's credit metrics to improve. The current rates, even with the improved PSA authorized in Decision No. 69663, are not enough to prevent a significant drop in the near term. Such a downgrade would severely undercut APS's ability to finance its required construction programs and would thus create a need for even greater rate relief at the expense of APS's customers.

Q. WHY SHOULD THE COMMISSION CONSIDER THE COMPANY'S CREDIT RATING AND CREDIT METRICS IN MAKING ITS DECISION IN THIS MATTER?

A. In a nutshell, the Commission should consider the Company's credit metrics and credit rating in this proceeding both because it is required by law to do so and because those factors are a measure of and have a significant bearing on the Company's overall financial health. A downgrade to junk status would hamper APS's ability to continue to provide reliable service to its growing customer base and would greatly increase APS's cost of service (and thus the rates it must

charge). A fundamental tenet of utility regulation is that customers require a financially healthy utility so that rates remain reasonable and service remains reliable. And the financial health of APS—dependent upon the revenue it is authorized to receive and the credit metrics it is able to achieve—is almost exclusively within the Commission's control.

These facts are not new to the Commission. Indeed, the Commission has historically recognized the very real importance of credit ratings, declaring that "the benefits of [higher bond] ratings inure to both the utility and the utility rate payer. We believe that sound and responsible regulatory action by this Commission is fundamental to the maintenance of desirable bond ratings." Decision No. 51009 (May 29, 1980). For this reason, as described below, the ultimate goal of APS in this proceeding is not only to obtain the requested rate relief that will allow APS to maintain its BBB- investment status in the short term, but also to establish a longer-term process that will restore the Company's financial health and return its credit ratings to the high BBB/low A range over the next several years.

Q. PLEASE ELABORATE ON THE CONSEQUENCES TO APS AND ITS CUSTOMERS IF THE COMPANY IS DOWNGRADED TO NON-INVESTMENT GRADE.

A. The adverse consequences of APS having its credit rating downgraded to junk would be immediate, serious, and long-term. The following is just a sample of the problems that come with non-investment grade credit ratings:

- With limited financial flexibility, APS's access to the debt and equity markets would itself become limited to those lenders and investors (if any) willing to take the risk on a junk grade company.

- Investors will demand a higher yield for an investment in a company with low credit ratings in order to compensate them for their increased risk, a factor that raises the cost of APS's capital at a time when capital requirements are extreme. Any debt or equity issued by APS would thus come with significantly increased costs due to the high interest rates and fees that inevitably accompany a junk credit status. As a result, by 2019, the Company's financing costs recoverable from customers could increase by as much as $70 million to $145 million per year over what they would have been absent a downgrade. This is the equivalent of a 2.7 to 5.5 percent rate increase to customers for each year that the Company remains non-investment grade.
- APS and its customers would lose much of the cost-savings currently enjoyed because of the financing arrangements underpinning the Company's $656 million dollars in outstanding tax-exempt debt. This debt requires letters of credit from banks or other third party insurance to support its creditworthiness, and pricing for that support is based exclusively on APS's credit ratings. A downgrade to junk status will significantly increase those costs by as much as $1.8 million per year, which costs are ultimately borne by APS customers in the form of higher base rates.
- APS's access to commercial paper—a cost-effective financing mechanism on which APS heavily relies for its working capital needs—would be completely eliminated. APS's average outstanding commercial paper debt is roughly $200 million, although that number could easily double at the peak of the Company's liquidity needs. APS's commercial paper is now rated A-3/F-3/P-2, which places it squarely in the limited

Tier-2 and Tier-3 market. Many commercial paper buyers have investment policies prohibiting them from purchasing APS's commercial paper because of APS's weak credit rating (indeed, only 4% of all commercial paper buyers are in the Tier-2 and Tier-3 market). For this reason, access to the commercial paper market has been a problem for APS on two separate occasions in the second half of 2007 when the financial markets were under stress. Should APS be further downgraded to non-investment levels, its access to the commercial paper market would be eliminated completely, and APS would lose all of the cost advantages that come with commercial paper, including daily liquidity and competitive pricing. APS would thus be forced to turn to more costly revolving credit agreements to satisfy its daily working capital needs, increasing APS's overall borrowing cost by $1.7 million annually. This increase, of course, ultimately leads to rising energy prices for APS customers.

- APS may also lose many of its important existing bank credit agreements if forced to fight for renewal of those facilities with a lowered credit status. The few banks that might renew these existing agreements would demand significantly higher prices and more onerous covenants that, in the event of increased financial stress, could drive APS into default and bankruptcy.
- Most of the Company's purchased power contracts contain provisions that require APS, in the event of a downgrade to non-investment status, to provide the counter-party with cash collateral (a "collateral call") to cover the difference between the contract price and the then-existing market price of the commodity. High levels of collateral calls could place a

significant liquidity strain on APS at a time when the Company's access to the capital markets is already restricted.

- If downgraded, many of the Company's purchased power and fuel contracts include prepayment provisions, requiring the Company to provide up-front cash payments for the Company's purchased power, power plant fuel and fuel transportation needs. APS's cost of doing business in the wholesale markets would increase significantly under such provisions, and the Company's ability to hedge against price volatility would be constrained, further increasing the Company's risk profile.

Q. WOULD ANY OTHER CONSEQUENCES RESULT FROM A DOWNGRADE TO JUNK GRADE?

A. Yes. Of all of the consequences described above, my greatest fear is that, if downgraded to junk, APS might entirely lose its access to the credit markets. In the last rate case, I testified that when credit markets are such that "investors in general have experienced a general decline in confidence, they regularly turn to what they perceive as less risky investments," and that, as a result, "non-investment grade issuers can find themselves shut out from sources of funding at the very time that they require them most." [Rebuttal Testimony of Donald E. Brandt, Docket No. E-01345A-05-0816, September 15, 2006]. That unstable credit market exists today. What began as a disruption in mortgage-related securities in the summer of 2007 has spread like a contagion throughout the debt and equity capital markets. Current financial markets are now in the very state of extreme volatility to which I referred in September of 2006, causing an increase in APS's financing costs even with the Company's current investment

grade credit rating. And, as I indicated in the last rate case would be true in such an environment, this highly volatile credit market has at times been closed to companies with below investment grade ratings.

APS has already experienced first-hand the volatility in the credit markets. For example, the mortgage-related securities market began experiencing difficulties in the summer of 2007. At that time, it became apparent that the default rates on so-called sub-prime mortgages were much higher than the market had assumed. This impacted the short-term debt markets for both mortgage-backed commercial paper programs as well as all other commercial paper programs. In August 2007, many issuers, including Pinnacle West, were not able to access the market and were forced to turn to bank credit to fund their working capital needs. The situation stabilized to a minor degree in the fall of 2007, but by December had once again deteriorated. APS entered the commercial paper market in mid-December and began experiencing historically high rates. As year-end approached, APS was unable to sell its commercial paper into the market and was forced to borrow over $200 million under its existing credit facilities to fund its short-term debt needs in late December. Additionally, most of the commercial banks that APS has turned to for liquidity and credit support have had to take massive, multi-billion dollar write-downs on their books related to investments in sub-prime mortgage products, severely impacting the amount of capital the banks have available for lending. This has resulted in a credit market in which supply has become limited yet demand has increased—a market from which a junk grade borrower will unlikely be able to borrow and in which interest rates will increase.

APS has experienced other negative financial impacts as a result of the credit market turmoil, even in its current investment grade position. For example, the Company has $343 million of long-term pollution control bonds that are sold to investors as auction-rate securities. Even though these securities are long-term, they trade in what has historically been a very liquid short-term market. This has allowed APS to fund long-term obligations at significantly lower short-term interest rates that reset weekly. In 2007, APS's pollution control bonds traded in the auction-rate market at interest rates that averaged about 3.5%. But, to accept the extremely low interest rates paid on auction-rate securities, investors require a guarantee that they will receive their interest and principal payments when due. This guarantee is provided by AAA-rated bond insurance.

In late 2007, credit rating agencies announced that some of the bond insurers appeared to have insufficient capital to cover their exposure in the sub-prime market—thus putting the AAA ratings at risk. In January of 2008, the bond insurer that backs APS's auction-rate securities, Ambac Financial Group, Inc., was downgraded from AAA to AA by Fitch Ratings. The Ambac downgrade flowed through to the bonds it insures, including APS's $343 million of auction-rate securities. The auction-rate market has since seen a dramatic loss of investors. If there are no willing buyers of the securities when they come up for auction, the existing bondholders are forced hold the bonds until the next auction. As compensation for holding what may be unmarketable securities, the existing holders are paid a premium rate—in the case of APS's securities, this rate is 14%—four times what it had been just last year. APS needs to maintain its investment grade credit ratings to be able to implement economic alternatives and to avoid paying a 14% rate on these securities.

Q. AREN'T THE CONSEQUENCES FROM DOWNGRADE THAT YOU HAVE JUST DESCRIBED SPECULATIVE?

A. No, they are not. The costly consequences resulting from a downgrade to non-investment status are neither speculative nor overstated, as confirmed by the experience of Nevada Power Company ("Nevada Power"), which was saddled with hundreds of millions of dollars of added costs and onerous borrowing restrictions as a result of their slide into "junk" status.

In a March 29, 2002 decision (Docket No. 01-11029), the Nevada Public Utilities Commission ("NPUC") disallowed a significant amount of deferred fuel and purchased power expense for Nevada Power. As a result, credit rating agencies lowered Nevada's senior debt securities ratings to junk grade, and Nevada promptly lost access to short-term debt markets. The resultant costs to Nevada Power and its customers have been extreme, increasing the cost of debt by more than $110 million *annually*, motivating the NPUC to implement several initiatives aimed at restoring Nevada to an investment grade position in the capital markets. For example, the NPUC enhanced the return on equity applicable to designated "critical facilities" (including those that protect reliability, promote diversity of supply, promote renewable energy or are statutorily mandated), authorized Nevada Power to include a portion of the utility's Construction Work in Progress ("CWIP") account balance in rate base in the Company's last rate case, enhanced the return on equity for approved DSM project costs, and implemented an automatic fuel cost adjustor. Even the Nevada legislature reacted to Nevada Power's downgrade by enacting statutes geared towards encouraging a positive regulatory environment.

E. Why Growth Is Contributing to APS's Financial Pressure

Q. YOU PREVIOUSLY INDICATED THAT CUSTOMER GROWTH IS NOT NEW TO APS. IF THAT IS TRUE, WHY IS GROWTH NOW EXACERBATING THE FINANCIAL PRESSURE ON APS THAT YOU HAVE DESCRIBED?

A. Although the Company's growth rate has remained reasonably constant over the past decade, customer growth today is substantially more costly than it was 10 years ago—a factor that, combined with other cost pressures that have caused the price of electricity to go up nationwide (even in low-growth areas), is placing extraordinary financial pressure on APS. As described in detail in the testimony of Mr. Ewen, APS's dollar investment in infrastructure per new customer is higher today than it has been historically for three primary reasons: first, the Company's infrastructure investment needs have risen considerably; second, the cost of the materials and supplies necessary to construct that infrastructure has sharply increased; and third, previously helpful trends associated with other non-fuel costs have reversed, thereby eliminating a significant source of cost savings that previously offset the other rising costs of growth.

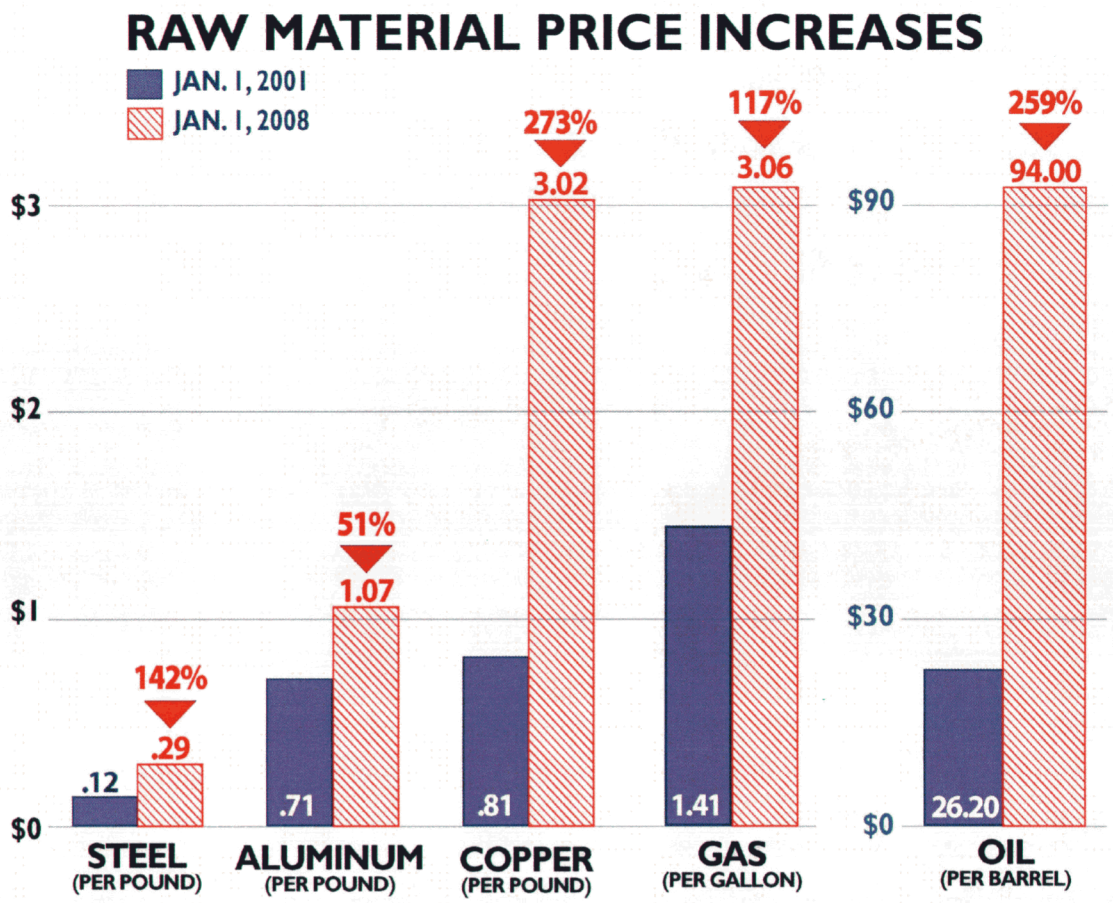
Q. WHY HAVE APS'S INFRASTRUCTURE NEEDS INCREASED IN RECENT YEARS?

A. A significant cause of the challenge APS now faces in paying for the cost of growth compared to prior years is the increase in system expansion needs that APS has seen recently—expansion needs requiring high levels of capital spending that were either not required or were offset by other cost-savings in the past. To that end, as Mr. Ewen explains, APS was able to meet much of its growing demand in prior years with its existing generation, transmission, and distribution system through a combination of infill opportunities and increased

system utilization. But growth has largely exhausted the capacity of the current system, which means that APS must expand and upgrade that system in order to meet its customers' rising energy needs. As a result, APS's distribution and other investment requirements have risen considerably. Thus, while the Company's current and projected customer and demand growth rates are reasonably comparable to those of prior years, APS's distribution, transmission, and generation infrastructure needs to serve those new customers have changed substantially. APS has little margin of capacity available to it now, so it must both expand its distribution and transmission system and upgrade its existing system in order to continue to provide reliable service to its growing customer base.

Q. YOU MENTIONED A SECOND FACTOR THAT MAKES GROWTH MORE EXPENSIVE TODAY THAN IT HAS BEEN IN THE PAST: RISING COMMODITY COSTS. PLEASE ELABORATE.

A. APS's escalating physical infrastructure and construction needs come at a time when the cost of materials, commodities, and land used for construction is considerably higher than it has been in the past. Each new physical plant addition thus comes at a disproportionately higher cost than it would have almost 10 years ago. Indeed, as shown in the following table, the prices of copper, steel, aluminum, and gasoline, to name only a few—materials that are vital to APS's construction program—are much more expensive now than they have been historically, and are expected to continue to rise faster than general inflation in the foreseeable future.



Graph DEB-9

As this table shows, from January 2001 to January 2008, the price of copper rose from 81 cents per pound to $3.02 per pound—an increase of 273%. As of April 1, 2008, the price of copper had further increased to $3.86 per pound—up 84 cents per pound in just four months, bringing the total increase since 2001 to 377%. As of January 2008, the price of aluminum had increased 51% from its 2001 price, rising from 71 cents per pound to $1.07 per pound as of January 2008. And aluminum prices, too, have risen since just the beginning of this year, increasing by another 26 cents to $1.33 per pound as of April 1, 2008.

Both commodities are significant components of distribution infrastructure costs.

Q. WHAT IMPACT DOES THE INFLATION IN COMMODITIES COSTS HAVE ON APS'S CONSTRUCTION COSTS?

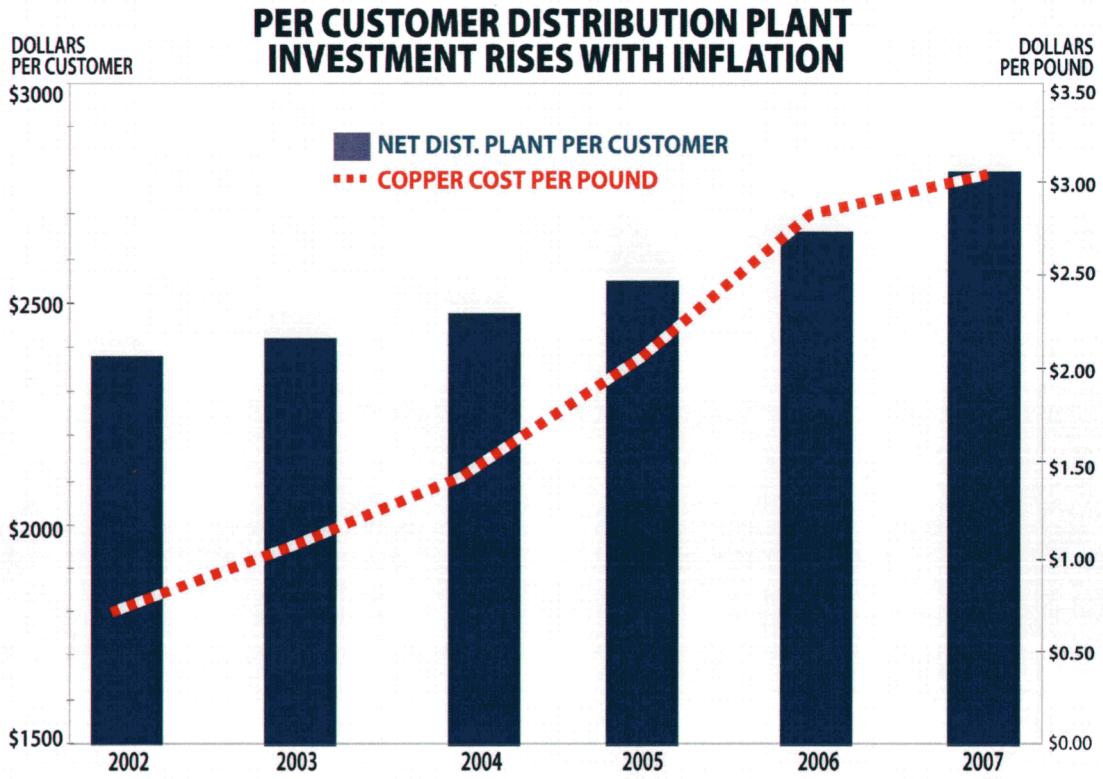
A. The effect of these price increases on APS's construction costs (and thus its capital requirements) is striking. For example, two pieces of equipment that are basic to virtually all electrical construction projects are steel poles and transformers. Steel poles are used, among other things, to erect power lines and support other electric supply infrastructure. A transformer is an electrical device that changes electric energy from one voltage to another, thus enabling electricity to be transferred over transmission and distribution wires at different voltages prior to ultimate distribution to the consumer. (For example, a transformer sitting on top of a neighborhood distribution pole might transform a typical distribution voltage of 7200 volts into the much lower 110 to 120 volts used in residences or businesses). As depicted below, steel poles and transformers of varying sizes and varieties are basic pieces of electrical equipment and are critical to the business of electricity supply.

Pad Mounted Distribution Transformer

Overhead Pole Mounted Distribution Transformer

The spike in commodities costs described above has had an extraordinary impact on the costs the Company is forced to incur for each of these two basic pieces of equipment. A 45 foot steel pole, for example, that cost $440 in 2000 now costs the Company $787—a 78% increase in price caused by inflation alone. A 500/230 kVA 3-phase transformer that would have cost APS $2.7 million in 2004 now costs APS $5.1 million—almost twice the price. A 50 kV distribution transformer now costs $1,626 compared to the $953 cost that APS would have paid in 2003—an increase of 70% in just five years. And these are just three examples of many.

There is thus a close correlation between the rise in APS's construction costs and the inflating cost of the materials and commodities used in that construction. The following graph depicts this correlation well, focusing exclusively on the Company's rising per customer distribution costs.



Graph DEB-10

As this graph illustrates, APS's per customer cost for distribution plant (after accounting for the impact of accumulated depreciation) generally tracks the inflation in the Company's key commodities costs, copper being a particularly striking example of the correlation. The Company's per customer distribution costs have risen from under $2,400 per customer in 2002, to more than $2,500 in the year 2005, to almost $2,800 per customer in 2007—an increase of approximately $400 for each of the Company's 1.1 million customers compared to what those costs were just five years ago. And this does not account for the per-customer cost increases required by the Company's growing transmission and generation projects, which have also grown substantially. So not only is APS required to build proportionately more infrastructure than it has in the past, the cost of that infrastructure is higher than it has been in recent memory and

continues to rise.

Q. YOU MENTIONED A THIRD FACTOR THAT MAKES GROWTH MORE COSTLY TODAY THAN IT HAS BEEN HISTORICALLY: THE REVERSAL OF NON-FUEL COST TRENDS. PLEASE EXPLAIN.

A. As Mr. Ewen describes in detail, APS's O&M and other non-fuel costs are increasing faster than they have in prior years, and APS is no longer able to take advantage of the economies of scale that historically offset the cost of growth. While APS generally saw a declining non-fuel cost trend over the early part of the last decade, that trend has reversed, resulting in inadequate earnings and weak credit metrics. That trend is compellingly depicted in the "Allowed APS Rates Are Confiscatory" graph displayed previously in my testimony, on page 26.

As that illustration shows, both APS's revenue from rates (adjusted to remove fuel expense to focus the analysis) and its non-fuel costs declined on average from 1995 to 2000, but rates generally remained above incremental costs. As Mr. Ewen explains, the general decrease in non-fuel costs occurred for a number of reasons, including aggressive cost management by the Company and a decline in property taxes and interest rates. The declining non-fuel cost trend experienced during the period 1995-2000 allowed APS to remain financially healthy while providing price decreases to its customers.

From 2000 to 2005, however, the financial health of the Company began to deteriorate. In part, this was driven by rapidly rising fuel costs, which the Commission largely resolved in Decision No. 69663. Another significant factor, however, was the turn-around in the non-fuel cost trend that the Company had seen in prior years. O&M expenses increased significantly after 2000, growing

faster than APS's sales. Depreciation expenses also rose. While some isolated non-fuel costs decreased, the net result was that, on whole, APS's non-fuel costs leveled-off, thus eliminating a significant source of financial relief for the capital cost pressures associated with the Company's growing demand. Exacerbating the problem, APS's customers received rate **decreases** until 2003, pursuant to Commission Decision No. 61973.

Today, the historically favorable cost trend that once offset the impact of the Company's increasing capital intensity has reversed, and APS has been and is continuing to feel the financial impact of the overall increase in its non-fuel costs. Depreciation expense continues to rise, but now at an increasing pace, and is no longer offset by other once-favorable unit cost trends. To the contrary, because of the previously discussed cost increases, APS's non-fuel costs are now rising and will continue to rise faster than its sales growth, absent rate relief.

Q. CAN THE COMPANY TAKE ADVANTAGE OF ANY ECONOMIES OF SCALE TO OFFSET THE COSTS OF GROWTH THAT YOU HAVE JUST DESCRIBED?

A. No. APS has exhausted any material economies of scale that may once have offset the costs of growth. By definition, economies of scale refer to the decrease in the unit cost of service that can result from large-scale operations. As I explained above, APS is now experiencing an *increase* in its non-fuel unit costs because of its growing operations and inflating material costs. Put another way, rising sales and increasing customers are not producing sufficient margins above operating costs to support the Company's capital costs, as the foregoing

discussion demonstrates. This fact demonstrates that economies of scale no longer exist.

VI. ACTIONS THE COMPANY HAS TAKEN TO ADDRESS THE CHALLENGES OF GROWTH.

Q. WHAT MEASURES HAS THE COMPANY TAKEN TO IMPROVE ITS FINANCIAL CONDITION OUTSIDE OF SEEKING RATE RELIEF?

A. APS has not simply witnessed the deterioration of its financial health like a disinterested observer. To the contrary, it has taken a number of significant steps to lessen the impact of growth and mitigate the Company's increasing earnings shortfall outside of the regulatory process.

APS has long realized that cost management is not a program or even a series of programs imposed by management or regulators, but rather a way of doing business. Because it has an obligation to serve anyone requesting service within its authorized service area at Commission-established prices (based, in large part, on average rather than marginal costs), APS does not have the luxury of refusing unprofitable business or unilaterally raising prices for customers who impose higher than average costs, which are essentially its incremental customers. Consequently, the Company has fostered a culture of cost management that stresses to every APS employee the importance of containing and, if possible, reducing costs while at the same time maintaining a high quality of service to APS customers. In that regard, APS's incentive program rewards employees whose business units operate cost-effectively.

The APS budgeting process reflects this culture of cost management. Budgets, both capital and operating, are closely scrutinized and monitored. Once approved, the budget becomes the measuring stick for subsequent operational

performance. Giving life to the adage that one "cannot manage what he does not measure," APS analyzes deviations from and holds each business unit accountable to its budget on a monthly basis.

In a letter to the Commission dated January 23, 2006, the Company outlined a long series of actions that APS has taken to successfully manage costs over the past 10 years. A copy of that letter is attached as Attachment DEB-5. As is indicated in that letter, APS has been very successful over a long period of time in containing O&M costs. Indeed, but for that success, it is doubtful that incremental APS revenues from growth would even cover its O&M and other operating costs, let alone provide any margin for capital costs.

In addition, APS continues to engage in its long-standing aggressive debt management practices, which have resulted in cost-effective debt refinancing that has saved the Company millions of dollars in financing costs. In the Company's recent Financing Application, Commission Staff specifically commented on those practices, noting that APS has used the financial flexibility enjoyed under a general financing authorization "to benefit and lower its capital costs." Decision No. 69947 (October 30, 2007).

APS also continues to diligently manage its labor costs and has significantly reduced its workforce per customer over the past decade. Indeed, the Company's customer to employee ratio has improved from 198 customers for every APS employee ten years ago to 224 customers for each employee today—an operational improvement that continues to save the Company millions of dollars in salary and benefits costs. In the area of fuel costs, the recent audits and studies on such costs conducted at the order of the Commission by Liberty

Consulting Group and R.W. Beck & Associates indicated that APS is prudently acquiring and, managing fuel and purchased power resources for its customers "in a manner that produce[s] reasonable and appropriate costs." [Direct Testimony of Staff Consultant John Antonuk at 4, 8/18/06.]

Q. HAS THE COMPANY DONE ANYTHING ELSE TO MANAGE ITS OPERATING COSTS?

A. Yes. In a more direct response to the Company's current financial crisis, APS has this past year closely scrutinized its organizational structure, further trimming costs and improving efficiencies in its two most manageable cost areas: O&M and capital. With respect to O&M, I personally engaged in focused meetings with each officer of the Company to ascertain where cost-reduction or cost-management opportunities might exist. I also retained CRA International (formerly known as Charles Rivers and Associates)—a national consulting group specializing in utility operations and cost management alignment—to advise APS on how it might sharpen lines of accountability, become more customer-focused, and enhance the speed and efficacy of decision-making. Based on input from CRA International and my officer team, APS underwent a reorganization that accomplished the following improvements, among others:

- APS created a Chief Customer Officer (Tammy McLeod) with responsibility for managing all aspects of customer service operations statewide, including customer marketing, research, call center, credit and collections, customer offices, aps.com, remittance processing, billing and metering.

- APS consolidated and tightened the management related to all of the Company's activities related to constructing and maintaining its distribution system into one business unit, under the management of the Senior Vice President of Energy Delivery (Jan Bennett).
- APS expanded the Energy Delivery business unit to include activities related to the development and planning of the Company's transmission system, in order to more closely align transmission and distribution planning and improve the speed and cohesiveness of decision-making regarding the Company's system infrastructure planning.

APS also recently announced that it will reduce its workforce with the aim of eliminating 100 positions now filled by current employees, 100 positions now filled by supplemental employees, and 120 currently vacant positions. The Company estimates that this reduction, once complete, should lower operating costs by some $7 million annually (which APS has reflected in a pro forma adjustment sponsored by Mr. LaBenz).

In addition to O&M, the Company engaged in a review of its capital spending. In that vein, I established internal teams to review the planning and budgeting processes associated with four specific areas—Fossil Generation, Delivery, Information Systems, and Facilities—with the objective of identifying opportunities to reduce capital costs without sacrificing APS's ability to provide reliable service to its customers. In each area, these teams evaluated how the forecasts underlying the capital budget were formulated, what factors drove that forecast (such as recent materials and price changes, changes in growth, and continued aging of existing equipment), how projects were prioritized, how projects were justified, whether alternatives to a specific project were viable and

what risk was involved in choosing alternatives, and the potential impact of deferring projects. As a result of this process, APS reduced its capital budget in a manner that helped it to partially mitigate the cost increases that the Company is experiencing from the rising costs of its key material and components.

All this being said, it is unrealistic to expect that cost management can, in and of itself, offset the disproportionate rise in the cost of new infrastructure necessary to serve APS customers. Exhortations to "work harder" and "work smarter" cannot change the fundamental nature of increasing marginal costs of serving an ever growing base of customers.

Q. HAS APS DONE ANYTHING ELSE TO RELIEVE THE IMPACT OF GROWTH?

A. Another significant way in which APS has responded to the challenges of growth is with its DSM programs and proposed rate offerings. Through year end 2007, the DSM programs implemented by APS and approved by the Commission have proven a highly cost-effective use of the funds provided by APS customers for these programs. The cost of the energy savings is approximately 1.0 cent per lifetime kWh saved—significantly cheaper than any alternative supply side resource. Capacity savings amount to over 60 MW, or roughly the size of a modern combustion turbine generator. But the current DSM recovery mechanism has short-comings that contribute to APS's attrition level, as Mr. DeLizio and Mr. Pickles discuss in their testimony. So that APS can continue to make DSM and demand response programs an essential part of its effort to manage growth in the years to come, the current DSM adjustor mechanism should be improved to eliminate the financial disincentives currently in place. Commissions in other jurisdictions have implemented similar types of

DSM cost recovery mechanisms that APS seeks here for other utilities, as Mr. DeLizio and Mr. Pickles describe.

Rate design has also been a part of the Company's response to the challenges of growth. APS instituted time-of-use ("TOU") rates in the 1980s—well before many other utilities in the United States. At present, APS has the largest number of customers on TOU rates (approaching a half million), both in absolute numbers and as a percentage of total customers, in the country. APS is also one of the few electric utilities in the country that offers demand rate options to residential customers, and all APS general service customers larger than 20 kW are demand metered. In total, this means that the large majority of APS customers can receive TOU and/or demand price signals through their rates to manage and reduce the peak demand for electricity, thereby reducing the costs to both customers and the Company associated with peak demand. APS will continue to explore other rate options in the Commission's open docket on the issue.

APS does not intend to stand pat with regard to rate design, as Mr. DeLizio describes. Proper price signals are a critical component of an overall demand response and DSM program. APS has worked with a national rate design consulting firm to develop several new innovative pricing options that it wishes to share with the Commission and other stakeholders in this proceeding. And as Advanced Metering Infrastructure ("AMI") becomes more pervasive throughout the APS service territory, the potential for yet additional and even more sophisticated pricing programs will be further enhanced. Although AMI is a source of cost-pressure for APS now, it will provide significant cost-savings opportunities for APS customers in the future.

VII. ACTIONS THE COMMISSION COULD TAKE TO HELP APS COPE WITH THE COSTS OF GROWTH

Q. WHAT CAN THE COMMISSION DO TO HELP THE COMPANY ADDRESS THE CHALLENGES OF GROWTH AND IMPROVE APS'S DETERIORATING FINANCIAL CONDITION?

A. This application proposes several regulatory tools that the Commission has used in the past and can use now to allow APS to charge electric rates that adequately compensate the Company for its cost of service at the time those rates become effective. Among other things, as detailed in the testimony of Mr. Kearns, the Commission can allow APS to include capital projects in rate base that were already underway at the end of the Test Year but have since been closed to plant or will be closed to plant (*i.e.,* capital projects that have been completed and are serving customers) by the estimated effective date of the final order in this matter, October 1, 2009 ("Post-Test Year Plant Additions"). The Commission can also allow the Company to adjust its revenue requirement to account for the earnings attrition that APS will continue to suffer from the Test Year through the year 2010, as Mr. Kearns will also discuss in detail.

By approving such mechanisms, in addition to the others described in this application, and allowing the Company to recover its total revenue requirements (including legitimately incurred expenses relating to SERP, stock compensation, and lobbying), the Commission will notably strengthen APS's financial health in the short term—which ultimately benefits customers by giving APS the ability to provide reliable electric service at lower long-run costs.

Finally, but importantly, the Commission should act on APS's application in as prompt a manner as possible in order to ease the significant financial impact of regulatory lag. The Company requests that the Commission consider this

application as quickly as possible and that it avoid the consolidation of this rate application with other APS matters that are now pending or may be pending before the Commission in other dockets.

Q. CAN THE COMMISSION DO ANYTHING ELSE TO IMPROVE THE COMPANY'S FINANCIAL CONDITION FOR THE LONG TERM?

A. Yes. Importantly, the $278.2 million net revenue request made in this filing will not alone return APS to its once high BBB/low A credit ratings nor restore the level of financial health that the Company and its customers enjoyed in the past. Instead, APS's immediate rate request will only allow the Company to maintain its current BBB- investment grade through at least 2010, requiring additional rate filings thereafter as APS's spending needs continue and rise and the threat of downgrade to junk persists.

It is crucial to recognize, however, that Arizona—like the rest of the country—is experiencing an energy demand crisis. The infrastructure and other energy investments the Company is making today and over the next decade are thus critically important in shaping the future of Arizona's communities, its environment, and its economy. APS envisions an energy future for Arizona that is cleaner, more efficient, more reliable, and that offers customers more control over how they use energy – all of which goals are shared by the Commission (in some cases, even required by it). But such aspirations come with tremendous costs, which cannot be borne by a financially unhealthy or unstable utility. APS cannot focus on investing in Arizona's needed generation and other improvements and innovations without rates that contemporaneously reflect the Company's cost of service, or if it is constantly distracted by the threat of

downgrade and the attendant financial pressures (pressures that are felt by the Company and customers alike) and the diversion of constant rate filings.

The Commission has the power to meet and defeat this threat over the long term. By taking a long-term look at Arizona's energy future and the vital importance of keeping the State's largest utility financially healthy for years to come—even under short-term pressure to keep rates at a minimum—the Commission can provide APS with the tools necessary to plan and build Arizona's future energy structure. History shows that keeping a long-term focus rather than merely depressing rates in the short run ultimately keeps customer costs down. Indeed, the electric debacle in California at the beginning of this century resulted largely because California focused on the short term to the detriment of the future.

In order to avoid an increasing cost of debt and the continual threat of downgrade, APS seeks to achieve 100% cash coverage of its capital expenditures over the next several years. Achieving this goal would place APS in the financial position necessary to internally generate the cash that APS requires in the upcoming years and restore the Company's credit ratings to their former high BBB/low A status. While such a goal would require substantial future revenue increases (of roughly $400 million annually on top of the current rate request) or the implementation of other innovative financial solutions aimed at restoring APS's former financial health, the long-term benefits to customers of avoiding rising debt costs in this volatile credit market and enjoying the financial benefits bestowed upon companies of a higher credit status are undeniable. Such innovative solutions may be similar to the alternative regulation mechanisms used in other jurisdictions or the use of a future test year – the same types of creative solutions recently suggested by various Arizona

Commissioners to address the issues raised by Arizona's growth and its impact on the State's utilities and electric prices. Solutions that will relieve the financial pressure experienced by customers and the Company alike are particularly important as Arizona pioneers its way through a new energy landscape—one that can provide reliable, clean, efficient energy for its growing population.

As part of this application, APS thus requests that—in addition to approving its request for an immediate revenue requirement increase—the Commission work with APS to consider such long-term solutions and devise a plan that will restore the Company's financial condition and return it to a high BBB/low A credit rating over the next several years, rather than approving a rate that will require frequent rate filings and keep the Company in its current credit rating status, just one step away from junk. Even with the Company's high capital spending requirements, such an upgrade is possible if the Commission implements supportive regulatory policies, such as pre-approval of power contracts and generation investments and mechanisms that reduce or eliminate the negative financial impact of regulatory lag, among other things. Indeed, in June of 2007, S&P upgraded Sierra Pacific Power Company's and Nevada Power Company's ratings outlook from stable to positive based exclusively on such positive regulatory support in Nevada, notwithstanding the likely erosion of these utilities' credit metrics in the short run resulting from capital spending requirements that proportionately rival those of APS. Among other things, APS thus asks that the Commission agree to conduct a post-order proceeding in this docket to be held the year after rates from this case are set to ensure both that

APS is earning its authorized rate of return and that it is on target for long-term financial stability and improvement.

A. Attrition Adjustment

Q. WHAT IS AN ATTRITION ADJUSTMENT AND WHY IS IT NECESSARY?

A. As previously described, the Company's current regulatory environment (which combines notable regulatory lag with an historical test year rate-making process) coupled with APS's increasing capital expenditure obligations have resulted in significant earnings attrition. By its nature, the existence of earnings and ROE attrition means that, without relief, the Company will continue to underearn its allowed rate of return. Moreover, the existence of earnings attrition means that the Company has exhausted whatever historic economies of scale might have existed to decrease the per kWh fixed costs related to serving APS's growing service territory. Significantly, as noted previously and in the testimony of Mr. Kearns, since the end of 2002, APS has suffered a **$321 million** cumulative earnings shortfall from its allowed rate of return. The ACC-jurisdictional portion of that number will grow by another **$384 to $454 million** by 2010, without relief from this Commission.

Q. HAS THE COMMISSION AUTHORIZED THE USE OF AN ATTRITION ADJUSTMENT IN THE PAST?

A. Yes, the Commission has specifically approved the use of an attrition adjustment for APS in the past. In both 1977 and 1980, for example, during times of high levels of capital spending associated with the construction of Palo Verde Nuclear Generating Station ("Palo Verde") coupled with disproportionately increased capital costs, the Commission recognized that its use of a historical test year would naturally produce rates that would result in earnings attrition. In

Decision No. 48139 (August 15, 1977), for example, the Commission recognized that "because [the Company's rate of return] is for a historic period, the Company will never earn the rates allowed. Attrition will set in." For that reason, the Commission granted APS an attrition allowance, thus providing APS the opportunity to earn its allowed rate of return.

Similarly, in Decision No. 51009, the Commission recognized with respect to APS that:

> Attrition does exist. In essence, company earnings are subject to erosion over time. While the effect of this phenomena may be minimal in some and possibly even most utility operations, the impact of attrition on a billion dollar plus company can be sizable. Earnings are based upon a test period which, though it be adjusted and modified, is still to some extent a model based upon a past period with historical costs and revenues. Time does elapse from the end of that period and those calculations and the entry of an order by the Commission. Over that period of time any rate of return set by the Commission on the test period will erode.

To mitigate against such an impact, the Commission approved an attrition factor that increased the Company's earnings in an effort to "to compensate [APS] for a very real phenomenon."

It is thus clear that the Commission has historically understood and authorized the essential benefit of an attrition adjustment during other times of significant financial stress for APS.

Q. HOW DOES APS'S FINANCIAL CONDITION NOW COMPARE TO WHAT IT WAS WHEN THE COMMISSION PREVIOUSLY ALLOWED APS AN ATTRITION ADJUSTMENT?

A. APS's financial condition is significantly worse now than it was when the Commission authorized an attrition adjustment and other regulatory mechanisms

during the Palo Verde construction days. In the 1980s, when the Company was building Palo Verde, the Company's credit ratings were downgraded and APS ultimately received an emergency rate increase and other relief due in large part to the fact that APS was experiencing a significant shortfall between its FFO and its capital expenditure needs. *See* Decision No. 53909 (January 30, 1984). However, as the following table shows, that shortfall is considerably worse now than it was when APS was constructing Palo Verde.

APS FFO vs. Capital Expenditures

(Dollars in Millions)

	1983	1984	1985	2009	2010
Funds from operations	$ 223.0	$ 300.9	$ 375.4	$ 780.9	$ 780.4
CapEx	359.7	328.0	445.9	1,087.8	996.3
FFO less CapEx	(136.7)	(27.1)	(70.5)	(306.9)	(215.9)
FFO as a % of CapEx	62.0%	91.7%	84.2%	71.8%	78.3%

As this table makes clear, the Company's FFO shortfall significantly exceeds what the Company experienced during its Palo Verde construction days, at which time the Commission provided APS with substantial financial relief (including an attrition adjustment, the inclusion of Post-Test Year Plant in Service, and an emergency rate increase). Absent adequate rate relief to address this shortfall again today, APS will have no choice but to issue ever-increasing amounts of debt—debt issuances that are expensive in today's unpredictable credit market. The combination of weak cash flow and the resulting need for additional debt will cause APS's FFO/Debt ratio to deteriorate, which will likely cause the Company to be downgraded to junk—a credit grade that, as I have

described, will inevitably increase borrowing costs, lower the value of common equity, and result in higher costs to customers.

Q. HOW DOES APS'S PROPOSED ATTRITION ADJUSTMENT COMPARE TO THE USE OF A FUTURE TEST YEAR?

A. As Mr. Kearns describes, APS's attrition pro forma is based on a detailed projection of the Company's capital and operating costs and its revenues from the Test Year through 2010—the first year that rates from this case will likely be in effect. It is similar to a future test year in that it gives ratepayers credit for sales growth that is expected to occur beyond the historic test year. It matches expected expense growth with expected sales growth for the same time period, to take revenues and expenses to the level at which they are expected to be when rates become effective. APS's attrition calculation then translates those changes into a single income statement pro forma that is added to all of the Company's other pro formas and layered onto the historic test year. Thus, the attrition pro forma adjusts the Company's income statement through 2010 in an effort to combat the negative financial impact of regulatory lag in the Company's high-spending, high-growth, inflationary environment, much like a future test year would do, while still using a traditional adjusted historic test year approach.

Q. HOW DOES THE COMPANY'S ATTRITION PRO FORMA COMPARE TO THE ATTRITION ADJUSTMENT THAT APS PROPOSED IN THE LAST RATE CASE?

A. The attrition pro forma adjustment proposed in this case is based on a detailed analysis of the Company's projected ACC-jurisdictional financials through 2010 and seeks to add a calculable, cost-based revenue deficiency adjustment to the Company's overall revenue requirement—one that is tied precisely to and

focused on APS's projected costs for that period and that can complement the current historic test year regulatory model. This attrition pro forma is thus more precise than the attrition adjustment proposed in APS's last rate case, in which the Company sought to reduce its earnings attrition by increasing its allowed ROE by a given percentage, without specifically tying the amount of that adjustment to the Company's projected ACC-jurisdictional costs.

Q. HOW CAN THE COMMISSION OFFSET THE BASE RATE IMPACT OF THE COMPANY'S PROPOSED ATTRITION ADJUSTMENT?

A. Because part of APS's significant attrition has been and continues to be caused by customer growth, APS has proposed an impact fee that would – in connection with the Company's newly revised Schedule 3 line extension policy – require growth to pay for a reasonable portion of the cost of growth. That fee, as described in the testimony of Mr. Rumolo, presents the Commission with the opportunity to reduce the impact of the attrition component of the Company's total revenue requirement on existing customers. It is important to recognize, however, that the adoption of APS's proposed impact fee is equitable only if the Commission grants the Company's attrition pro forma adjustment. Unlike the attrition component of APS's revenue requirement deficiency, APS's non-attrition-related revenue requirement is, for the most part, caused by an increase in costs required to serve all customers, both new and existing alike. To require new customers alone to pay for a portion of the costs required to serve all customers through the use of an impact fee would be unfair and unreasonable. For this reason, the non-attrition portion of the Company's revenue requirement deficiency should stand on its own in base rates.

B. Post-Test Year Plant In Rate Base

Q. WHAT DOES IT MEAN TO INCLUDE "POST-TEST YEAR PLANT ADDITIONS IN RATE BASE?"

A. In seeking to include post-Test Year plant in rate base, APS proposes that the Commission include in rate base the dollars that the Company had already invested in capital projects that were not in service at the end of the Test Year, but that will have closed to plant by the time rates go into effect. While any given plant is under construction, the Company must generate the funds to build that plant. These funds are either generated internally or they are acquired in the financial community (in the debt and/or equity markets). Although the utility has invested current funds in that plant, it has not been permitted to place the capital spent on that construction in rate base (and thus include it in determining the Company's revenue requirements) until the construction is complete and the plant is actually placed in service. In the interim, the capital expenditures are recorded on the balance sheet and accrue an accounting return in what amounts to capitalized interest and equity return in the form of "Allowance for Funds Used During Construction" ("AFUDC"). AFUDC is recorded in book-keeping entries but is not a cash return. However, AFUDC stops accruing when the plant is placed in service. The utility does not begin earning a cash rate of return on that plant until its next rate case. In the meantime, once that plant goes on-line, it begins to depreciate and incur property taxes and O&M expenses.

A regulatory mechanism that would allow the Company to include such plant in rate base (thereby allowing APS to earn a return on that plant, as well as recover book depreciation and property tax expenses) would improve both cash flow and earnings. In this case, as described by Mr. Kearns, APS seeks to include in rate

base the dollars that the Company had already invested in capital projects that were underway at the end of the Test Year, all of which are now or will be closed to plant in service before the rates requested in this application will go into effect – an adjustment that adds $251.3 million to the Company's rate base. Of that amount, 21% relates to projects that had already closed to plant-in-service at the time this filing was submitted.

Because of its direct relation to the Company's construction program, this tool is particularly useful to prevent the erosion of earnings and cash flow that will otherwise result from the high levels of capital spending required in APS's growth environment. Moreover, because this adjustment produces a return on actual costs the Company has already incurred, the costs are known and measurable and the adjustment is thus consistent with the Commission's prior methodology. In fact, to ensure that the Post-Test Year Plant Additions adjustment is based on known and measurable costs, the Company proposes to periodically update its pro forma calculations throughout this proceeding, including prior to the Open Meeting in this matter.

Q. HAS THE COMMISSION AUTHORIZED THE INCLUSION OF POST-TEST YEAR PLANT IN RATE BASE IN THE PAST?

A. Yes. Like the attrition allowance, the Commission has specifically approved the use of post-Test Year plant in rate base, as have Arizona courts. In fact, multiple Commission decisions in the late seventies and early eighties allowed APS to *both* include post-Test Year plant in rate base and to recover an attrition allowance in an amount necessary to recover the margin of underearning that was not recovered by the inclusion of post-Test Year plant alone. *See, e.g.,*

Decision Nos. 48139 and 51009. With respect to the inclusion of post-Test Year plant, the Commission's words then are equally applicable today:

> Arizona Public Service Company has an extensive construction program which, upon review, we consider to be sound and appropriate, based upon the information presently available. The amount of such construction is placing a burden on the Company that will have deleterious effects unless compensated for. Historically, we have seen excessive attrition in the earnings of the Company primarily caused by the burdens of the construction program. To partially offset that attrition and to give appropriate earnings to the Company based on plant that will soon be coming on line, we are going to allow a certain amount of CWIP for APS.

See Decision No. 48139. And even more recently, the Commission has approved some level of post-Test Year plant in rate base in each of the Company's last two rate decisions.

The Arizona Supreme Court has expressly confirmed the Commission's legal ability to include these amounts in rate base, stating that "[t]he Corporation Commission in its discretion can adopt any of the various approaches used by public utility regulatory bodies in considering plant under construction as long as the method complies with the constitutional [fair value] mandate and is not arbitrary and unreasonable." *See Arizona Corporation Commission v. Arizona Public Service Co.,* 113 Ariz. 368, 371 (1976). The historical test year model does not bar the use of such regulatory tools. To the contrary: "[I]t is obvious that the Commission in its discretion can consider matters subsequent to the historic test year. . . ." *Id.*

Far from questioning the legality of these innovative regulatory mechanisms, the Arizona Supreme Court has encouraged their use, opining that it is in "the public

interest to have stability in the rate structure rather than a constant series of rate hearings." *Id.* APS could not agree more.

C. Employee Incentive Compensation

Q. DOES APS SEEK RECOVERY OF ITS EMPLOYEE INCENTIVE COMPENSATION COSTS IN THIS PROCEEDING?

A. Yes. As described in detail during the last rate case, APS has an incentive program that grants both cash and stock incentives as part of overall employee compensation. This incentive package was designed to allow APS to compete with other companies in the market to attract, motivate and retain key management employees, and is a vital part of APS's compensation program. Long-term incentive programs like APS's are offered by countless companies—including most other utilities—throughout the country. Stock incentives, in particular, have been the fastest growing component of management compensation in utilities nationwide for more than fifteen years. As the most recent competitive analysis of APS's executive compensation program shows, 93 percent of the Company's utility peers provide long-term incentives to management in the form of stock-based awards (*e.g.*, stock options, restricted stock, and performance shares) and/or cash awards.

The cash component of the Company's incentive compensation program was expressly approved in the Company's last rate case. But the stock component is just as important. Not only does the stock incentive motivate management employees to take a long-term view of the Company by granting them a proprietary interest in the Company's growth and success, it does so without requiring a current outlay of cash—an important consideration for any company experiencing cash flow shortfalls like APS.

Q. IN DECISION NO. 69663, THE COMMISSION DISALLOWED THE COMPANY'S STOCK INCENTIVE COSTS. WHY HAS APS SOUGHT RECOVERY FOR EMPLOYEE STOCK COMPENSATION AGAIN IN THIS CASE?

A. Again, with due respect to the Commission, APS is convinced that the Commission erred in disallowing the Company's stock incentive costs in the last rate case. In Decision No. 69663, the Commission did not dispute that cash and stock incentives both play a vital role in attracting and retaining high quality management personnel. As explained above, stock incentives are routinely offered by companies, including most other utilities, across the country and are essential to allowing APS to attract and recruit the market's best and most knowledgeable management employees. Nevertheless, the Commission disallowed the Company's stock incentive costs based entirely on speculation, suggesting that such incentives might motivate employees to "perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate." Decision No. 69663 at 36. The Commission based this finding solely upon the testimony of a Staff consultant who opined that enhanced earnings levels may hypothetically be achieved by "short-term" management decisions that could discourage the development of safe and reliable utility service at the lowest long-term cost. *Id.*

But the Company's stock incentive plan does not reward and would in fact discourage such short-sighted decisions, nor was there any evidence in the last rate case that suggests that any APS manager has acted contrary to the long-term interests of the Company and its customers in order to reap some hypothetical short-term stock benefit. By its very nature, the Company's stock incentive plan rewards solid performance over the long-run, not in the short term. Stock

incentives align the interests of APS employees and directors with the interests of APS customers and shareholders by tying a portion of the employees' total compensation to the Company's long-term financial performance. In so doing, stock incentives encourage the development of safe and reliable utility service at the lowest cost—motivating management to keep reliability high with minimal operating costs, which is very much in the interests of APS customers. As APS employees are acutely aware, any short-term decision that sacrifices reliability may send operating costs upward in the long run, thus working to the detriment of APS's earnings and, in turn, Pinnacle West's stock value. Stock incentive recipients benefit financially by holding onto their stock and contributing to the long-term success of APS, not by attempting to artificially inflate Pinnacle West's stock prices to some minimal extent by making a bad business decision that has adverse financial consequences to the Company and its customers down the road.

Far from engendering a conflict of interest that works to the detriment of APS customers, the stock incentive program provides important benefits to APS customers, by, among other things:

- encouraging an employee's ownership and longevity in the Company thereby minimizing costs associated with high turnover at the executive level;
- minimizing the need for increased base pay or other fixed benefits to provide competitive compensation levels; providing focus and accountability for the management team to develop and implement efficient and effective business strategies that span multiple year periods; and

- encouraging long-term financial health for the Company that, in turn, provides stability and allows the Company to continue to invest in the business's operations and improve operating efficiencies, all to the benefit of APS's customers.

In the end, there is little difference between compensating employees with shares of stock and paying them in cash, and the stock price is known and measurable. If the Commission takes no exception to the total compensation level paid to APS employees, there is no reason to disallow the stock incentive component of those overall compensation expenses.

D. Supplemental Excess Benefit Retirement Plan ("SERP")

Q. YOU MENTIONED PREVIOUSLY THAT THE COMMISSION CAN ALSO HELP THE COMPANY ADDRESS ITS FINANCIAL CHALLENGES BY ALLOWING THE RECOVERY OF LEGITIMATELY INCURRED OPERATING COSTS, INCLUDING SERP, LOBBYING, AND STOCK INCENTIVE COMPENSATION. WHAT IS SERP, AND WHY IS IT NECESSARY?

A. "SERP" refers to the Company's Supplemental Excess Benefit Retirement Plan. Like the vast majority of companies, including utilities, APS offers a standard benefit pension plan to its senior management employees that includes the ability to participate in SERP—a supplemental retirement plan that allows these employees' retirement pensions to be based on their total compensation rather than the limited portion of it deemed "qualified" for pension purposes by the Internal Revenue Service ("IRS"). This includes both income above an amount designed by the IRS and even those amounts of income below that level which the employee has elected to defer. SERP is an integral part of the Company's retirement plan for senior management and is a key component of APS management compensation.

Q. IN DECISION NO. 69663, THE COMMISSION DISALLOWED THE COMPANY'S SERP EXPENSES. WHY HAS APS SOUGHT RECOVERY FOR SERP AGAIN IN THIS CASE?

A. With due respect to the Commission, APS believes that the Commission erred in disallowing SERP in its last rate case and asks the Commission to reconsider the issue now. APS believes strongly that it must offer SERP in order to attract qualified, knowledgeable senior managers. By offering SERP, APS is able to compete with other businesses to hire the best management available—a critical need for a business struggling with the challenges that APS faces. APS's senior managers have a significant impact on the operations and condition of APS and it is essential that the Company be able to compete for and retain experienced management employees. In order to do so, APS must provide these employees with competitive market pay and benefits.

Decision No. 69663 disallowed the Company's SERP expenses, suggesting that the supplemental retirement package—which, much like a 401K plan, is intended to allow participating employees to receive benefits during retirement based on their respective pre-retirement salary—is not "reasonable" because it exceeds the retirement benefits offered to other employees. This logic fails on two counts.

First, it is incorrect to suggest that, by being offered SERP, APS senior managers unreasonably enjoy a benefit that is not offered to other APS employees. Far from being "unreasonable," SERP is necessary in order to protect APS management from being penalized in retirement for earning a base salary above the "qualified" level that is arbitrarily set by the tax code or by deferring amounts below that level. Other APS employees are not so penalized,

and thus do not need the additional retirement plan. APS is entitled to design the individual components of its compensation package: base salary, incentive pay and benefits—including SERP. These are legitimately incurred costs, and APS has included them in its cost-of-service.

Second, what is "reasonable" in a competitive employment environment is dictated by the market. In order to attract and retain experienced and highly qualified professionals, APS must compete with companies in other sectors of the economy and country. An important facet of that competition centers on compensation, including retirement benefits, and SERP forms an integral part of the total compensation package. The Company could not effectively compete for executive and management talent without offering SERP unless APS were to substantially increase base compensation by more than the amount of the SERP.

E. Lobbying Costs

Q. DOES THE COMPANY SEEK RECOVERY OF ITS LOBBYING EXPENSES IN THIS APPLICATION?

A. Yes. Consistent with the Commission's directive in Decision No. 69663, APS seeks recovery in this proceeding of fifty percent of the lobbying expenses incurred by the Company's Federal Affairs and Public Affairs departments, thus sharing the costs of the Company's lobbying activities equally between customers and shareholders. Given the urgency of the Company's need over the next decade to fund billions of dollars of new investment in Arizona's electric infrastructure, it is imperative that lawmakers—many of whom are now focused on developing energy policies that, in whatever form they ultimately take, will have significant impacts on the Company and its customers—are apprised of the issues facing Arizona in general and APS in particular. Informing public

officials about topics crucial to the Company and its customers and helping shape public policy are both critical tasks for the Company – efforts that go a long way towards providing significant cost-savings to both APS and its customers. The Company's lobbying activities and the benefits that those activities bring to APS and its customers are described in the report attached hereto at DEB-6.

VIII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR DIRECT TESTIMONY?

A. Yes. Growth and inflation are neither new nor unique to APS. What has changed is the fundamental trend of costs associated therewith. Whether attributable to disproportionately higher commodity and materials costs, declining customer density, exhaustion of historic economies of scale, the lack of fortuitous offsets or some combination of all these, the trend of increasing marginal costs to serve is undeniable. And although continued cost management is critical, so is regulatory support for policies that will better match incremental revenues with incremental costs. Some of these policies will require changes to both the procedure and substance of some recent APS rate-making decisions. Others will merely reflect the current adoption of proven policies from past Commission decisions. APS should not be required to tolerate an inherently confiscatory rate-setting process that produces hundreds of millions of dollars in earning shortfalls and jeopardizes the financial well-being of the Company. APS urges the Commission to approve the mechanisms proposed by this application and consider the long-term future of Arizona so that the Company

can regain its financial health and allow APS to continue its long-standing tradition of reliably providing an essential public service to Arizona consumers.

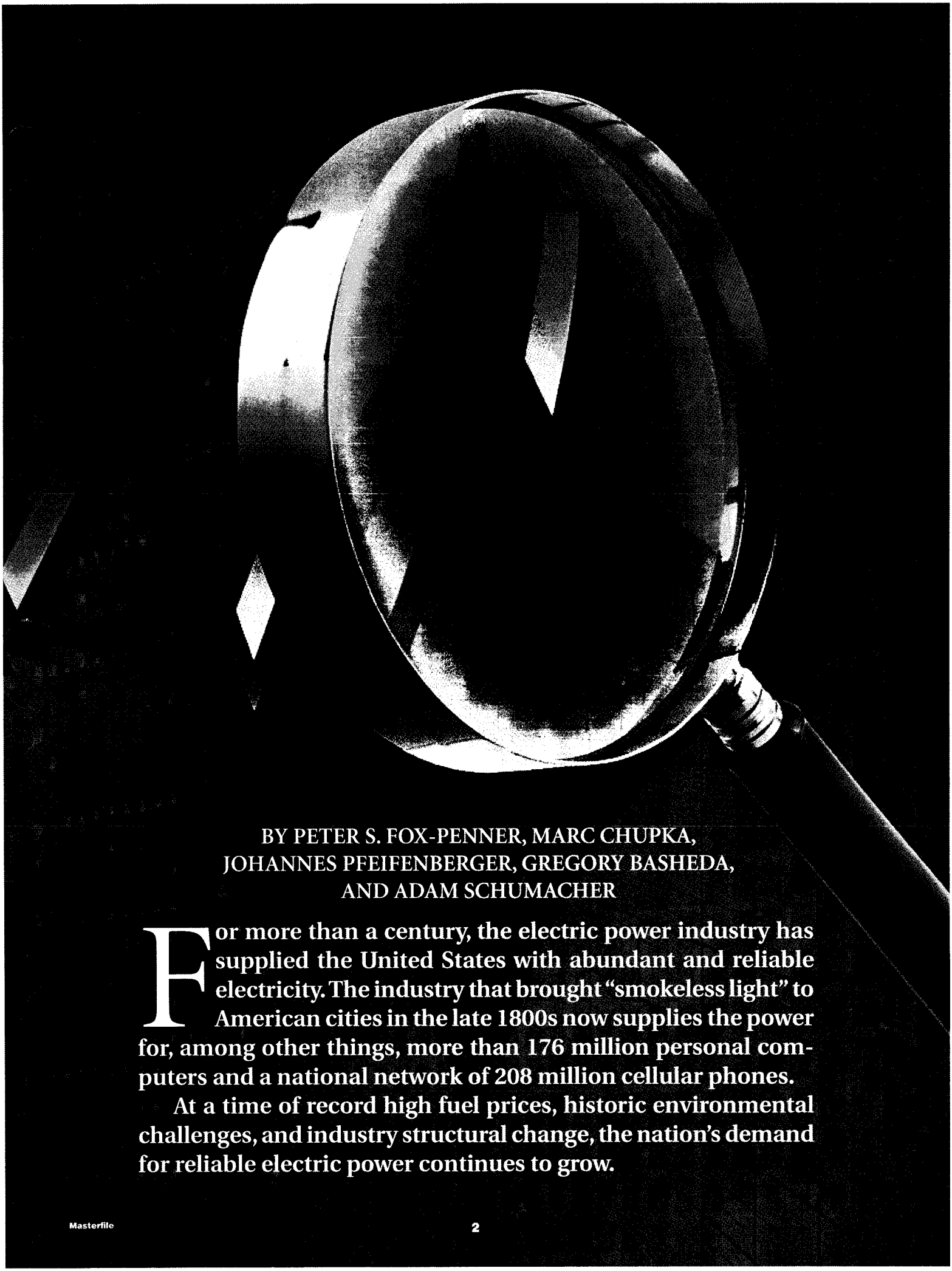
Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEHIND THE RISE IN PRICES

ELECTRICITY PRICE INCREASES ARE OCCURRING ACROSS THE COUNTRY, AMONG ALL TYPES OF ELECTRICITY PROVIDERS. WHY?

REPRINTED FROM JULY/AUGUST 2006 *ELECTRIC PERSPECTIVES*



BY PETER S. FOX-PENNER, MARC CHUPKA,
JOHANNES PFEIFENBERGER, GREGORY BASHEDA,
AND ADAM SCHUMACHER

For more than a century, the electric power industry has supplied the United States with abundant and reliable electricity. The industry that brought "smokeless light" to American cities in the late 1800s now supplies the power for, among other things, more than 176 million personal computers and a national network of 208 million cellular phones.

At a time of record high fuel prices, historic environmental challenges, and industry structural change, the nation's demand for reliable electric power continues to grow.

Masterfile

While much of the nation's power infrastructure is aging, the industry must keep up with the need for more capacity, increased reliability and power quality, and lower environmental impacts. Thus, the industry must invest in a new generation of power plants, environmental controls, and transmission lines to reduce the impact of high fuel prices and increased reliance on gas-fired generation.

This new investment will maintain reliability, diversify our fuel mix, and increase environmental performance—but it comes with added costs. To one degree or another, electricity price increases are occurring across the United States, among all types of electricity providers. The extent to which companies recover cost increases in rates will in good measure determine the industry's financial condition and its ability to make the next generation of investments in a timely manner. With appropriate rate treatment, the industry can continue to provide reliable services at reasonable costs. But if segments of the industry cannot finance new investments in a timely or cost-effective manner, then local economies and consumers served by these electric companies, as well as utility shareholders, will bear much greater costs. Failure to receive favorable rate treatment could have an impact on the quality of service, the industry's ability to meet growing demand for clean, reliable power, and the industry's financial health.

What factors underlie the recent increases in prices and the potential impacts of these cost increases on the industry's financial condition? Let's look at the drivers and the cost changes in the recent past and the trends for the next several years.

This article is based on *"Why Are Electricity Prices Increasing? Causes and Potential Effects,"* a white paper published under the auspices of the Edison Foundation in Washington, DC. The Foundation is a nonprofit organization founded to provide knowledge, insight, and leadership to the goal of bringing the benefits of electricity to families, businesses, and industries worldwide. To view an electronic copy of the full paper (109 pages, with figures), visit www.eei.org.

This is Part I of a two-part article. The second part, to appear in the September/October 2006 *Electric Perspectives*, covers the potential to reduce demand through utility-sponsored conservation and load management programs.

Fuel Expenses

Fuel and purchased power costs have risen substantially and are by far the largest cause of recent electricity price increases. On an industry-wide basis, these account for roughly 95 percent of increases in total operations and maintenance (O&M) costs experienced by electric utilities in the last five years.

Between 2002 and 2005, average annual O&M expenses for shareholder-owned electric utilities increased approximately 22 percent. (See Figure 1.) By 2005, fuel and purchased power expenses amounted to 71 percent of total O&M expenses, compared to 66 percent in 2004.

Peter Fox-Penner, Marc Chupka, and Joannes Pfeifenberger are principals, Greg Basheda is senior consultant, and Adam Schumacher is an associate at The Brattle Group in Washington, DC.

For power companies in states without retail restructuring, fuel is a core component of expenses, often passed through to customers in fuel adjustment clauses. In states that have pursued restructuring, utilities face higher purchased power expenses. Indeed, the increases in the cost of fuels—for fossil-fuel and nuclear plants, which comprise 90 percent of U.S. national net generation—have been unprecedented.

The spot price for natural gas (that is, the price for immediate, one-time purchases) has increased 100 percent since 2003 and more than 300 percent since 1999. Real natural gas prices are now at their highest level in modern history. While it accounts for nearly 20 percent of all generation, natural gas has a strong influence on electricity prices in the wholesale market because it represents the incremental generation in most high-demand hours. As spot markets increasingly affect the price of purchased wholesale power and retail real-time prices, the marginal cost of a generating company's most expensive unit sets the hourly prices that affect customer prices as well as longer-term purchases.

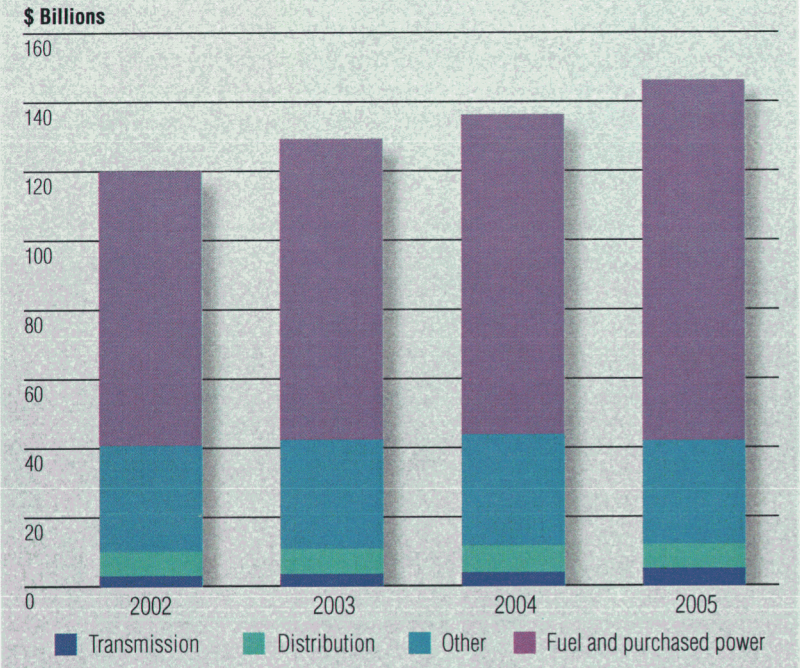
The price of natural gas has always been somewhat higher and more volatile than coal, but over the last few years natural gas price levels and volatility have increased dramatically. This has occurred during an era when gas-fired capacity has dominated the new capacity market, leading to new plants running less than expected or in some cases not running at all. Moreover, unlike coal, natural gas has several end uses other than generation: In 2004, the electric power sector accounted for only 26 percent of natural gas delivered to end use customers. The combination of price spikes related to weather, continued economic growth, and the expansion of NGCC capacity all contribute to pressures on the supply of natural gas.

Much uncertainty exists about the direction of delivered natural gas prices. (See Figure 2.) The significant volatility in prices for natural gas—and different views regarding longer-term structural market issues and the price of liquefied natural gas—have contributed to this wide variety of projections.

Coal accounts for half of all net generation in the country; and electric utilities use 92 percent of all coal consumed. The vast majority of coal volumes are under long-term multi-year contracts. Prices for delivered coal under these contracts declined in nominal terms for 15 years, starting in 1985. Between 2003 and 2005, however, delivered coal prices to electric generators increased by more than 20 percent.

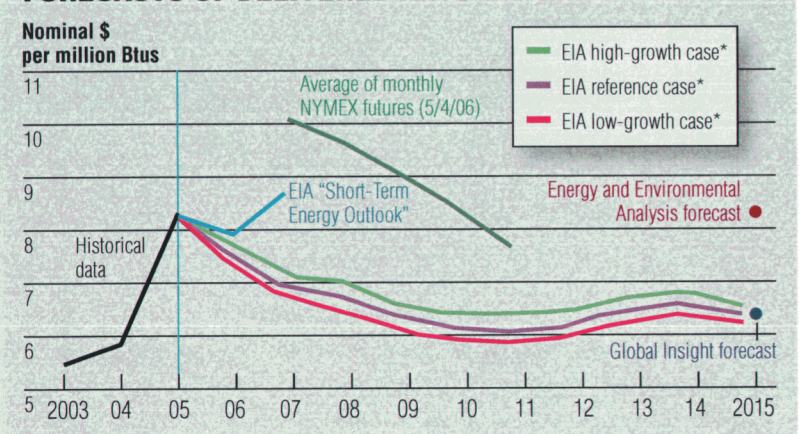
Spot prices have risen in every major geographic region of coal production. For example, prices at the Powder River Basin moved from $6 per short ton in March 2003 to about $15 per short ton in March 2006. As long-term contracts begin to expire, the effect of increasing spot coal prices will become more pronounced in delivered coal prices.

FIGURE 1
DRIVERS OF OPERATIONS AND MAINTENANCE EXPENSES



Source: FERC Form 1

FIGURE 2
FORECASTS OF DELIVERED NATURAL GAS PRICES

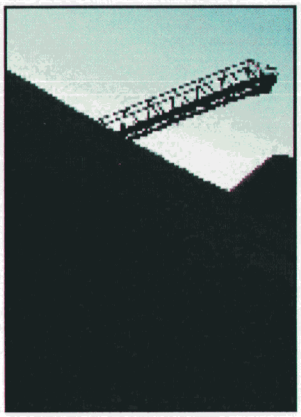


EIA–Energy Information Administration
*from EIA "Annual Energy Outlook 2006"

Coal prices have risen for several reasons. High natural gas prices have shifted some demand from gas to coal, while rising oil prices have driven up the costs of coal mining and shipping. While prices also reflect transportation-related shocks, such as recent train derailments in the Powder River Basin, they do not directly reflect the price of transportation, which is growing with overall energy prices.

Also, record high emissions allowance costs in the sulfur dioxide (SO_2) permit trading market—from $200 per ton in 2003 to nearly $1,600 per ton in late 2005—have had a significant impact. Allowance prices have retreated from their 2005 highs, but as allowance allocations shrink in the future, new clean air regulations come into effect, and generators install controls on smaller, more expensive units, those prices may gradually rise again.

With the expected lag between spot price movements and ultimate delivered prices to electric generators, prices should continue to escalate in the near-term as new contracts begin to reflect the higher commodity cost of coal. (See Figure 3.) Long-term forecasts differ, reflecting the uncertainty related to this critical input cost.

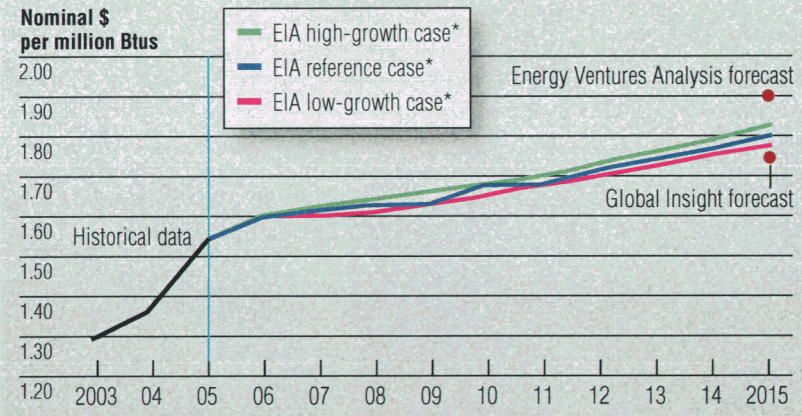


Oil, still a significant utility fuel in several parts of the country (New York and New England, for example), is now at record price levels. The prices of oil-based fuels delivered to electric generators have risen 50 percent between 2003 and 2005 and are now at the highest nominal levels ever recorded. Moreover, the Energy Information Administration (EIA) expects oil prices to remain at these high levels for the foreseeable future. And though it represents only 3 percent of net U.S. generation, in some regions it sets the marginal price during peak hours.

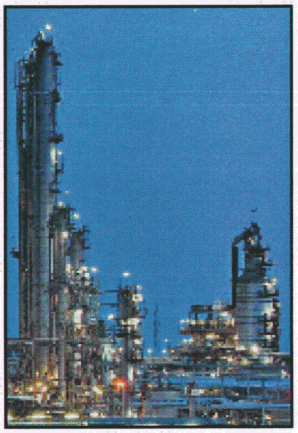
Historically, average petroleum prices have tracked the movements of natural gas prices. EIA's projections of delivered petroleum prices show steady to declining nominal levels in the near term, with steadily increasing prices after 2010. Thus, regions that are more exposed to petroleum-fired generation can expect price movements similar to that of natural gas and coal.

Finally, although the fuel component for nuclear energy is a relatively small portion of operating costs compared to fossil fuels, the price of uranium, which is purchased largely from foreign suppliers,

FIGURE 3
FORECASTS OF DELIVERED COAL PRICES



EIA–Energy Information Administration
*from EIA "Annual Energy Outlook 2006"



jumped as well—by about 40 percent between 2001 and 2005.

The Power Utilities Buy

Fuel price increases have had a significant impact on purchased power, with the cost of spot purchases increasing between 200 and 300 percent in the country's organized power markets in the last two years. To fulfill load-serving obligations, many electric companies—especially those in states that have undertaken restructuring efforts—rely on power purchased in wholesale markets, where prices primarily respond to natural gas during peak hours and coal in the off-peak hours.

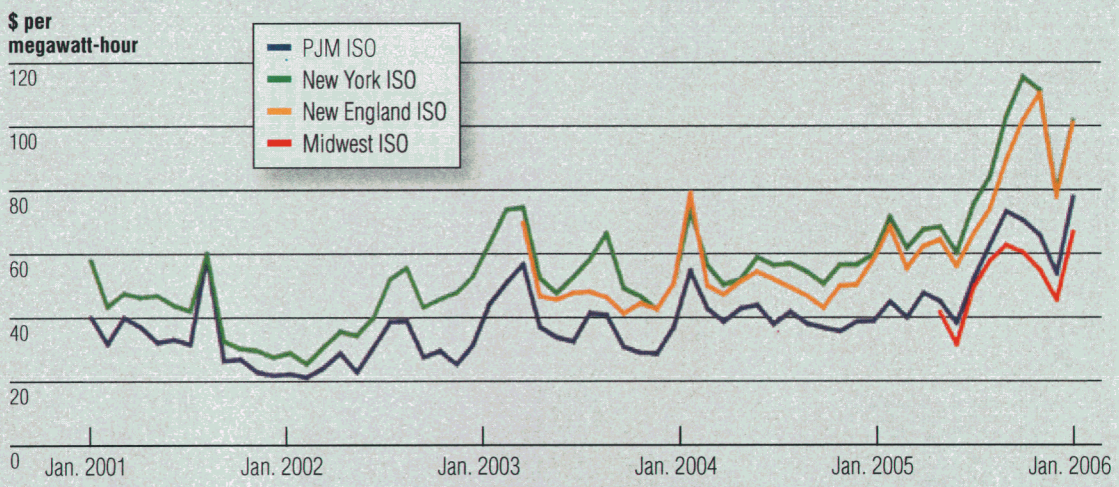
Average prices have risen gradually upward since 2002. (See Figure 4.) These averages of daily prices have varied from about $21 per megawatt-hour (MWH) to more than $116 per MWH in the Eastern power markets. During 2005, spot prices on nearly all markets rose by almost 100 percent, mirroring the increases in fuel costs. Bilateral energy markets also have experienced similar upward trends—and a doubling of prices in 2005. (See Figure 5.)

Price volatility is expected in commodity markets and can provide market participants useful short-term signals. Electricity markets are particularly volatile because, unlike most other commodities, electricity cannot be stored and its demand is highly price inelastic (that is, demand is relatively unresponsive to price). This makes electricity prices particularly sensitive to sudden changes in market conditions, such as the loss of a large generating plant or transmission line, or large shocks in input costs.

All to Meet Demand

Several projections expect steady growth in U.S. electricity demand for the foreseeable future. (See Figure 6.) Even after accounting for greater penetration of more efficient end-use equipment and potential customer responses to higher prices, EIA projects anywhere from 11 percent to 17 percent growth in total demand from 2006 to 2014. As a result, utilities will need to make major new capacity investments during this period. [See Part II of this article in the next issue of *Electric Perspectives*.] Both EIA and the North American Electric

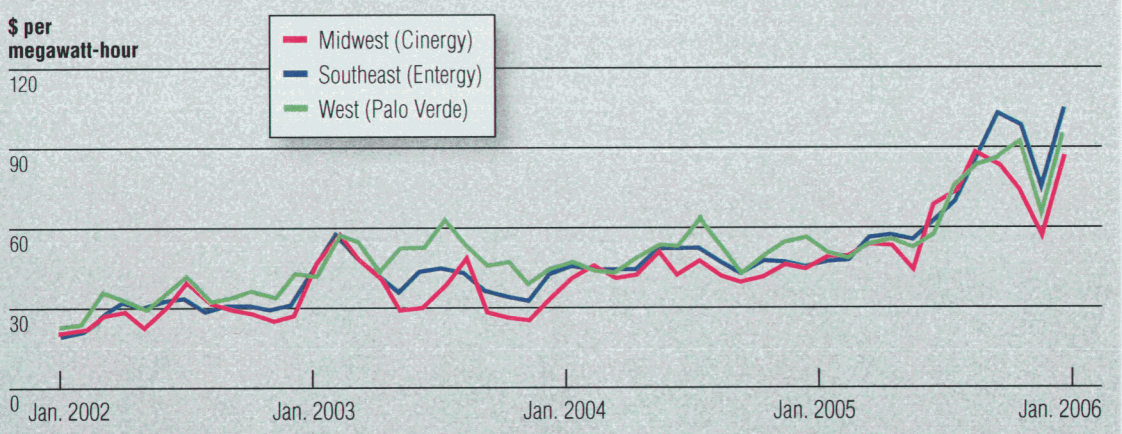
FIGURE 4
AVERAGE DAY-AHEAD ENERGY PRICES, 2001-2005



Source: Global Energy Decisions

FIGURE 5

AVERAGE DAILY BILATERAL ELECTRICITY PRICES AT MAJOR HUBS, 2002-2005
(by month)



Source: Global Energy Decisions

Reliability Council (NERC) estimate that the nation will need more than 50,000 MW of new capacity through 2014.

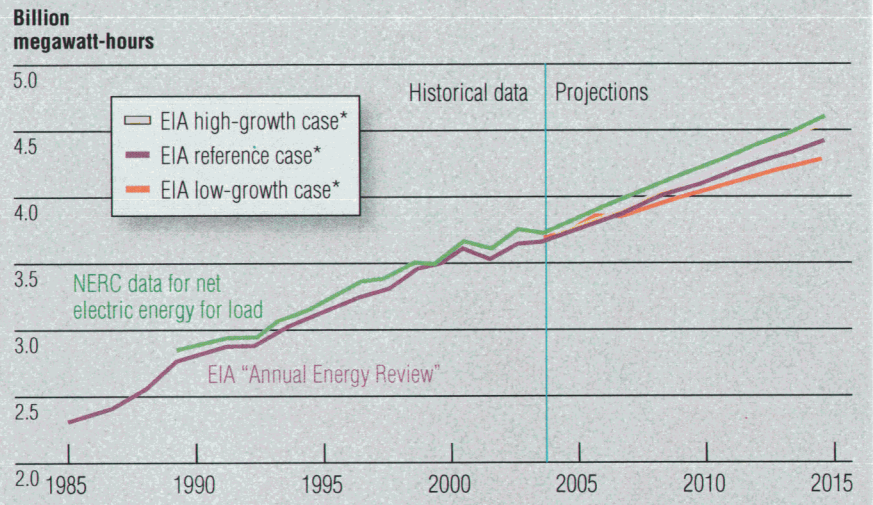
In light of those projections (as well as high natural gas prices and provisions in the Energy Policy Act of 2005—EPACT—that promote resource diversity and the development of baseload technologies), several companies have proposed or are building new baseload coal and nuclear power plants for the first time in more than 15 years. This new generation investment varies substantially by region. Right now, there is sufficient generating capacity in most regions of the country to meet current and near-term peak demands reliably. Some regions, however, (such as the West Coast, Florida, and portions of the Northeast) face more immediate needs for new generating capacity to maintain generation adequacy. Other regions may not necessarily need new resources to meet demand but rely heavily on gas-fired generation and may add coal-based and renewable power sources to diversify the fuel mix and reduce the total cost of electricity. Indeed, low use of NGCC capacity and high, volatile electricity prices in regions where natural gas influences wholesale prices have put the focus on fuel diversity at both the federal and state levels.

EPACT requires states to consider means by which they can minimize dependence on any one fuel source and to ensure that electricity is produced or procured from a diverse range of fuels and technologies, including renewables. (See the sidebar, "The RPS Factor.") Coal and nuclear plants enjoy substantial operating cost advantages over NGCC, though they are much more expensive to build and face more intensive permitting requirements and longer construction times.

EIA projects that the next generation of baseload construction will begin slowly, with coal and nuclear plant completions accelerating over the next 10 to 20 years and more renewable capacity in the next 10 years. (See Figure 7.) The capacity totals in the figure indicate expected completion dates of new plants, so they lag the bulk of construction

FIGURE 6

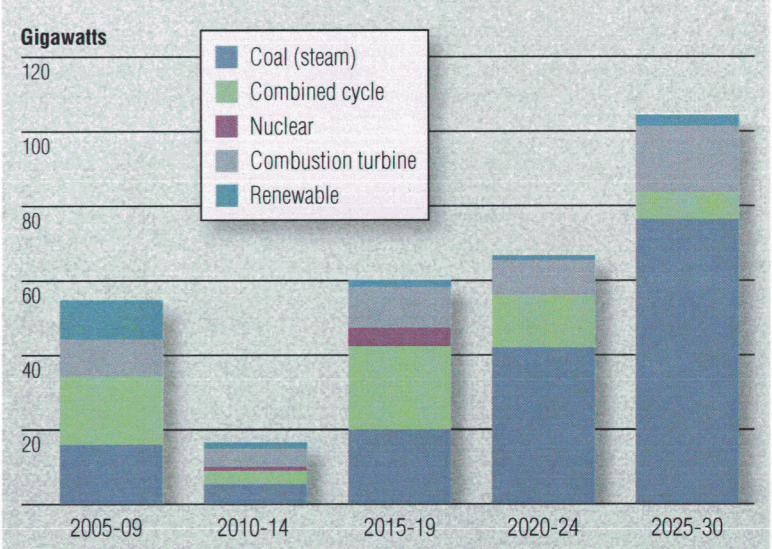
U.S. ELECTRICITY DEMAND, 1985-2014



EIA—Energy Information Administration
NERC—North American Electric Reliability Council
*EIA "Annual Energy Review"

expenditures by several years. Indeed, construction expenditures associated with plants completed between 2005 and 2009 have already been partially incurred. Moreover, the smaller amount of capacity assumed in service between 2010 and 2014 does not imply a commensurately smaller degree of capital investment during that period—this is also a time when much of the capacity anticipated to be online in the 2015-2019 period will be under construction.

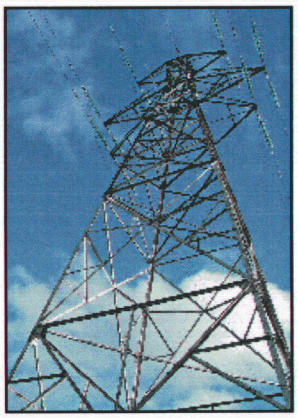
FIGURE 7
PROJECTED CAPACITY ADDITIONS



Source: "EIA Annual Energy Outlook 2006"

More Investment for Transmission

The U.S. and Canadian transmission grid includes more than 200,000 miles of high-voltage (230 kilovolts and greater) lines that ultimately serve more than 300 million consumers, who depend on the grid for access to reliable and reasonably priced electricity. This system was built over the past 100 years, primarily by vertically integrated utilities that generated and transmitted electricity locally for the benefit of native load customers.



To increase reliability and allow utilities to share excess generation, the electric industry also built interconnections between neighboring utilities. In recent years, as federal policy initiatives have promoted the development of regional power markets, the transmission system has also become a critical facilitator of those markets.

The U.S. electricity delivery system—the transmission grid and the downstream distribution system—is a $360-billion asset, but it is an aging infrastructure. (See the sidebar, "Transmission Grid of the Future.") According to the Department of Energy, 70 percent of transmission lines are 25 years or older, 70 percent of power transformers are 25 years or older, and 60 percent of circuit breakers are more than 30 years old. The strain on the system is beginning to show, particularly as it performs market-oriented functions for which it was not originally designed.

While NERC believes that the existing transmission grid is sufficient to provide reliable service in the near term, the council acknowledges that some portions of the grid will not be able to support all market transactions. In addition, NERC believes that regional transmission networks will operate near or at their limits more frequently in the foreseeable future. This implies that the transmission system, while reliable, will experience greater congestion: At times, it won't be able to accommodate all desired transactions, and system operators will have to use relatively high-cost generation in place of lower-cost generation to serve customer demand.

The RPS Factor

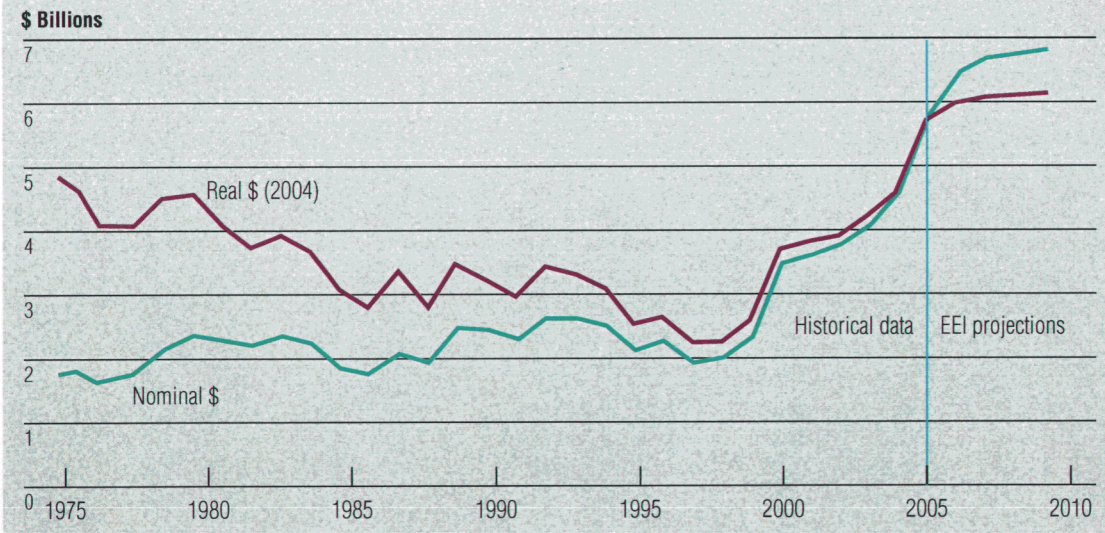
The primary advantages of renewables are stable operating costs (with zero or low fuel costs) and the environmental benefits of few or no air or water emissions. However, renewable technologies tend to have a higher cost per installed KW and lower capacity factors than traditional technologies. Also, their power output is generally intermittent, due to the variable nature of the resources. Renewable resources also vary quite substantially in their geographic distribution.

The desire to reduce exposure to high natural gas prices has given a strong extra impetus to renewable mandates at the state level. Twenty states and the District of Columbia have established renewable portfolio standards (RPSs)—mandates that retail electricity suppliers obtain a portion of total load from renewable energy technologies. The mandated portion of renewables and the compliance deadlines vary a good deal.

Estimates also vary on the amount of renewables that electric companies will build to meet the standards. EIA's "Annual Energy Outlook" forecasts about 10 gigawatts (GW) of additional renewable capacity over the next 20 years; the Union of Concerned Scientists estimates about 30 GW.

It is too early to tell just how RPS policies will contribute to electricity price increases—many of the ambitious targets lie in the future. But to the extent that companies procure renewables at prices above conventional sources or that they purchase renewable energy credits, such mandatory obligations represent additional costs that should be recovered in rates.

FIGURE 8
ANNUAL TRANSMISSION CONSTRUCTION EXPENDITURES, 1975-2009



Source: EEI

Increasing congestion and the aging power delivery infrastructure have spurred calls within the industry and many federal and state agencies to expand transmission investment.

Such investment declined between 1975 and 1999—for shareholder-owned companies, it fell at an average rate of $83 million per year. It began a significant upward trend from 1999 to 2003, however, by an average of nearly $286 million per year, totaling nearly $18 billion in the period. In a May 2005 survey, Edison Electric Institute (EEI) found that companies planned to spend $29 billion in transmission infrastructure from 2004-2008, a 60-percent increase over the previous five years. (See Figure 8.) Both stand-alone transmission companies and vertically integrated utilities are planning more investment. Only a small portion of this, 6.5 percent, is for direct generator interconnections—that means that most investment will support network upgrades, improved transfer capability between regions, improved reliability, and enhanced local, regional, and inter-regional markets. NERC projects almost 12,500 miles of new transmission by 2014, an increase of 5.9 percent.

These increased investments are prompted in part by the fact that the next wave of generation additions are being built farther from load centers, often for environmental reasons or to be close to fuel sources. In addition, many new transmission projects are larger and costlier than the average project over the past 20 years.

Also, in much of the country, transmission planning has been formally regionalized. Regional transmission organizations are explicitly including economic considerations in transmission plans. Moreover, power markets are creating greater price transparency, highlighting the value of transmission expansion and promoting investment.

Transmission Grid of the Future

The knowledge-based economy of the future will require a smart-power delivery system that links information technology (IT) with energy delivery. The revolution in IT that has transformed other industries has yet to occur fully in the electric power business.

For example, some of today's transmission system still relies on electro-mechanical switches—the same switches that were eliminated from consumer television sets 20 years ago. According to a recent study by EPRI, "Electricity Sector Framework for the Future," the digital controls that will replace these will become the foundation of a new "self-healing" power delivery system. Moreover, this technology will address the combined reliability, capacity, and security vulnerabilities of today's power delivery systems.

The smart-power delivery system includes automated capabilities to recognize problems, find solutions, and optimize delivery performance in real time. The basic building blocks include advanced sensors, data-processing and pattern-recognition software, and solid-state power flow controllers. These technologies will enable system operators to

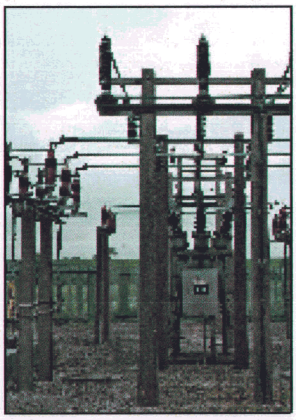
- optimize the overall performance and resilience of the system,
- instantly respond to disturbances to minimize their impact, and
- restore the system after a disturbance.

With greater real-time information, system operators can predict, diagnose, and mitigate issues that might previously have caused an outage or blackout.

It is unclear how quickly we will transition to a "smart grid," but the cost of doing so would be significant. EPRI suggests that research, development, and deployment costs to transform the transmission system would approach $200 billion over 20 years.

Drivers for Distribution Investment

The transmission system feeds substations that reduce voltage and spread power to smaller distribution lines. Generally speaking, the distribution system begins where voltage is reduced to 37 kilovolts, but the important distinction is that distribution involves delivering the power to the retail customer, while transmission involved moving bulk power to distribution systems.. The distribution system also includes metering, billing, and other related infrastructure and software associated with retail sales and customer-care functions.



First and foremost, the growth in customer demand requires continual investment in distribution facilities. Industry spending on distribution has followed a generally steady upward trend for the past 20 years. Between 2000 and 2004, spending went from about $10.5 billion to $12.5 billion, a 19-percent increase.

This steady climb in distribution investment shows no sign of diminishing. If recent investment trends persist, outlays for distribution will average $13 billion per year over the next 10 years. This is almost triple the projected amount of annual investment in new transmission capacity and is likely to exceed capital spending on generation capacity over the next decade as well. This level of distribution investment would lead to a cumulative 3.5-percent increase in retail rates over the next 10 years. Aging infrastructure, population growth, power quality, and customer service, all continue to motivate utilities to improve their systems.

Other factors—storm damage, aesthetics, and local land use rules—will also spur spending. For example, hurricane and storm damage in the southeastern United States during 2005 required sizeable distribution outlays. Also, in several cases, governments are directing electric companies to place new or existing distribution lines underground, particularly in urban areas. Undergrounding existing lines costs approximately $1 million per mile—a five- to tenfold increase over the cost of a new overhead power line. Moreover, a new underground system to replace an existing overhead one would require an investment of more than 10 times what a typical shareholder-owned electric utility currently has invested in distribution plant.

Distribution investment is also necessary for increased reliability. (See the sidebar, "Distribution for Digitalization.") The current electricity infrastructure was designed to serve analog, or continuously varying, electric loads—it cannot consistently provide the level of quality power required by the nation's digital manufacturing assembly lines, information systems, and high-tech home appliances. In these digital end uses, an outage of less than a fraction of a single cycle can disrupt performance. In the end, an enhanced distribution system delivering higher quality power will stimulate more widespread use of productivity-enhancing digital technology.

Conventional meters, which record cumulative energy usage and are usually read once a month by a utility employee, serve most customers. Advanced "smart" interval meters can track power usage by time of day, diagnose problems, and react to price signals. Digital meters can monitor power usage and (increasingly) perform other functions such as monitoring power quality, detecting theft, and facilitating prepaid electricity purchases. By collecting energy data on a real-time basis, smart meters will help power companies better understand consumption patterns and help customers cut energy usage. The meter will become a consumer gateway that allows price signals, communications, network intelligence, and perhaps even power generated by the customer to flow back and forth through the energy/information portal.

Installing new meters will be an expensive undertaking, however. Some experts estimate that about 10 million of the 130 million residential meters installed throughout the United States have advanced technologies. An advanced meter costs between $100 and $150, so purchasing meters for

Distribution for Digitalization

It is not an exaggeration to say that we are experiencing a "digitalization of society"—today, there are more than 12 billion microprocessors in the United States alone. For every microprocessor inside a computer, 30 operate in standalone applications. Indeed, digital-quality power now represents about 10 percent of total electric load in the country. EPRI projects that digital-quality power load will reach 30 percent in 2020 under business-as-usual conditions.

Three technologies will enable companies to provide digital-quality power and other enhanced distribution value.

- **Distribution automation** uses advanced sensors and control software to improve the ability to detect and correct disturbances more quickly, thus reducing customer outages and power quality problems.
- **Custom power systems** are electronic controllers that can provide real-time network control, protect sensitive customer equipment from network disturbances, and protect distribution feeders from power disturbances generated by the customer. These systems improve power quality for customers with special needs—for example, an industrial park with high-tech companies.
- **Generation and storage technologies** for distributed applications will move the power supply closer to the point of use, providing improved quality, reliability, and flexibility. Systems will need to be updated to integrate an array of locally installed, distributed power generation (such as fuel cells and renew-

120 million residential customers would be an investment of approximately $12 billion to $18 billion.

Environmental Investments

The electric power industry has long faced environmental regulation; and environmental protection has long been a driver of industry investment. While these investments pay dividends in terms of cleaner air, water, and land, they require capital investment and increased operating costs, which ultimately must be recovered in higher rates.

According to the most recent national survey of environmental expenditures, electric generators spent a total of about $3.5 billion in 1999 for environmental compliance—almost 12 percent of total industry environmental spending in the United States. (See Table 1.) These 1999 figures do not reflect several new compliance burdens, which primarily involve additional investments at existing facilities. According to an EEI survey of recent 10K reports, electric utilities spent at least $3.2 billion in 2005 on environmentally related capital investments alone. Outlays for environmental requirements may be the industry's fastest-growing investment category over the next few years.

Largely as a result of investments in air-emissions-reduction technology and of policies that target existing generating plants and other industrial sources, the air has become significantly cleaner since 1980. Emissions of SO_2 and nitrogen oxides (NOx) from electricity generation have declined by nearly one-half since then, while electricity generation has increased by more than 70 percent. By 2020, electric generation will be more than double 1980 levels, and those emissions will fall to one-quarter of their 1980 levels.

Three new rules in particular have substantial requirements. The Clean Air Interstate Rule of 2005 targets SO_2 and NOx in the Eastern United States to reduce fine particulates and ozone. In the West, the Clean Air Visibility Rule requires additional controls to reduce haze that affects national parks. The Clean Air Mercury Rule will address mercury emissions for the first time. In 2004, about one-third of coal units subject to the three new rules had advanced environmental controls; compliance with the rules would raise that proportion to two-thirds by 2020. The rules would increase the proportion of total capacity with advanced controls from about 50 percent to almost 80 percent by 2020.

The Environmental Protection Agency (EPA) estimates that the three regulations will cost electric companies about $3 billion per year in 2010, rising to more than $6 billion per year in 2020. The estimate for the overall net present value of all outlays between 2007 and 2025 is about $50 billion, with roughly one-half of that from capital investments in emission controls. The costs would be larger under alternative proposals. Moreover, many states are adopting rules that go beyond federal requirements.

Mandatory reductions of carbon dioxide (CO_2) have been under consideration for some time, at both the state and federal levels. The impacts of a mandatory policy would fall heavily on the electric generating sector. In addition, uncertainty over the pace of CO_2 controls creates costly risks.

TABLE 1
POLLUTION ABATEMENT AND CONTROL EXPENDITURES, 1999
($ millions)

Industry segment	Air	Water	Solid waste	Multimedia	Total
			Capital expenditures		
Electric power generation	1,071	55	17	2	1,145
All industries	3,464	1,802	362	182	5,810
Electric power generation share	30.9%	3.1%	4.7%	0.9%	19.7%
			Operating costs		
Electric power generation	910	100	127	27	1,164
All industries	5,069	4,587	2,013	196	11,864
Electric power generation share	18.0%	2.2%	6.3%	13.7%	9.8%

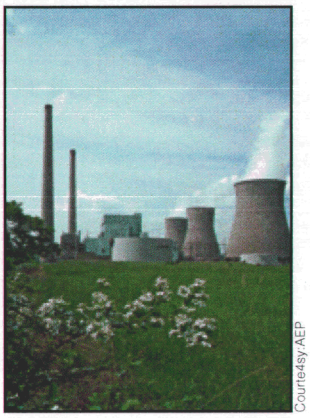
Total capital expenditures and operating costs for other activities*	
Electric power generation	1,215
All industries	12,205
Electric power generation share	10.0%

Aggregate total capital expenditures and operating costs	
Electric power generation	**3,524**
All industries	**29,878**
Electric power generation share	**11.8%**

*Disposal and recycling, pollution prevention, payments to government, and other.
Source: U.S. Census Bureau

Commercially available and economically feasible retrofit or new-plant CO_2 reduction technologies do not exist for coal-based generation. Still, many companies are making investments influenced by the prospect of CO_2 controls. Utilities have been leaders in voluntary projects to reduce greenhouse gas emissions or sequester CO_2 emissions. In some states, too, integrated resource planning requirements stipulate that utilities consider CO_2 policy risks; to the extent that resultant investment plans reflect CO_2 controls, near-term costs may increase.

Generating technologies that produce fewer CO_2 emissions come at significant expense. Integrated gasification combined cycle (IGCC) is a "clean coal" technology that presents a more economic opportunity to capture emissions. Nuclear power generation currently is the most significant non-CO_2 emitting baseload generation technology. And renewable electricity (except for biomass) is largely CO_2-emission free, too. Mandatory CO_2 limits would boost the economic prospects of renewable energy—but the costs of new plants generally remain higher than conventional generation, and renewable generation is usually not considered baseload.


Courtesy AEP

Electric companies also face significant new investments to comply with recent rules requiring modification of water intake structures to minimize adverse impacts on aquatic organisms. According to EPA, the Clean Water Act's Section 316(b) Phase II program will add $400 million per year in costs for electric generators, a substantial increase in the current level of expenditure on water quality. This figure could be higher depending on the flexibility companies have as they implement the rule.

Other environmental costs arise in waste disposal (e.g., coal and scrubber waste), recycling (e.g., coal ash used in cement), hazardous waste handling, and land and wildlife management. Together, these expenditures are substantial and rising.

With the partial exception of climate change controls, the costs for all these requirements are showing up in utility capital plans. The EEI survey revealed a total of up to $40 billion in planned capital investments and other environmental expenditures over the next 10-12 years. Estimates of the costs of potential CO_2 controls on electricity suppliers are uncertain, but the costs imposed on electricity generation under most policies would dwarf the amounts spent on other air emissions, water, and land. The impact on electricity rates would be roughly proportional to the costs imposed on the industry.

The financial impact of these outlays depends on the cost-recovery mechanisms, which vary by state and by company. Some states with traditional regulatory structures have mechanisms for full cost recovery of environmental compliance expenditures; others incorporate these costs into general rate cases, which can delay recovery. For states with deregulated retail markets, capital cost recovery is not assured. Generators depend primarily on market-clearing prices above their variable costs for contributions to fixed costs. Here compliance costs may simply go unrecovered and result in added financial stress for energy companies during a period when then are making investments to ensure adequate capacity.

Looking for Headroom

With reasonable rate relief, the electric power industry as a whole should have the ability to make the necessary, cost-effective investments in infrastructure and environmental protection. Without rate relief, however, the industry has proportionately less "headroom" to make investments. Certain portions of the industry are already below investment-grade and therefore cannot weather greater financial impairment.

The fraction of utilities rated BBB+ or above by Standard and Poor's (75 percent prior to the 1990s), is now only about 45 percent. As of 2005 nearly 20 percent of all utilities are rated BBB- or below investment grade; ratings of independent power producers are much worse.

Between 1999 and 2005, interest rates, allowed utility return on equity (ROE), and earned ROE all trended downward, so that the declining earned ROEs remained reasonably close to allowed ROE. However, the prospects for earnings, absent adequate rate increases, are getting worse. Costs are rising much faster than revenues, utility risks are up, and interest rates are no longer on a downward trend.

In 2005, the operating cash flows of utilities had declined significantly which must be expected to be a leading indicator for further declines in utility earnings. In addition, operating cash flows were insufficient—by $10 billion—to cover the utilities capital expenditures and higher operating costs. This gap is likely to widen significantly during the next several years, which will force utilities to rely increasingly more to rely on external sources of funds. To ensure reasonable rates in the long term it will consequently be important to maintain a regulatory environment that supports financially healthy utilities with cost effective access to capital markets. This will be more challenging than in recent years because utility costs and rates are increasing.

Putting It All in Perspective

In order for electric utilities to remain financially viable in the current era of increased operating costs and continued need to invest in infrastructure, rates must increase. Indeed, electricity prices in many regions already have risen, and further increases will be necessary in many cases. For ex-

ample, between January 2005 and January 2006, U.S. electricity prices increased by an average of 11.6 percent, which predominantly reflected increased fuel and purchased power expenses. These increases were actually smaller than the utilities' increase in fuel costs: The prices of fossil fuel consumed by utilities in 2005 were 30 percent higher than those paid in 2004. Still, residential rates rose by 12.5 percent, commercial by 10.5 percent, and industrial by 12.6 percent.

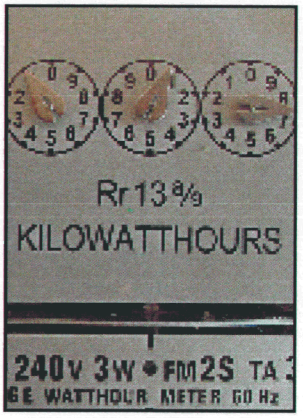
But put this in perspective. Even with these increases, electricity's price has risen less over the past few years than nearly every other product or service Americans buy—and among energy products, much less. Moreover, in many parts of the country, electric rates have not gone up for several years.

As we look at trends in average rates of retail electricity by customer class, what is striking is the relative stability in nominal rates until the first half of this decade. (See Figure 9.) In real (that is, inflation-adjusted) terms, rates have been declining for the previous two decades. (See Figure 10.) From 1985 to 2000, average electricity prices rose 1.1 percent/year, less than half the average inflation rate of 2.4 percent. American homes use 6 percent more power today than they did in 1978. Yet even with that greater use, the portion of the household budget we devote to our power bill has declined. (See the sidebar, "Household Power Use.")

At the same time, prices for most other products have increased substantially in keeping with the rate of inflation. At any point in time prior to the beginning of this decade, the pace of growth in electricity prices has been slower than that of other energy products and core components of the consumer price index (CPI). For example, between 1995 and 2005, prices for electricity increased by 17 percent, while inflation for all items increased 28 percent.

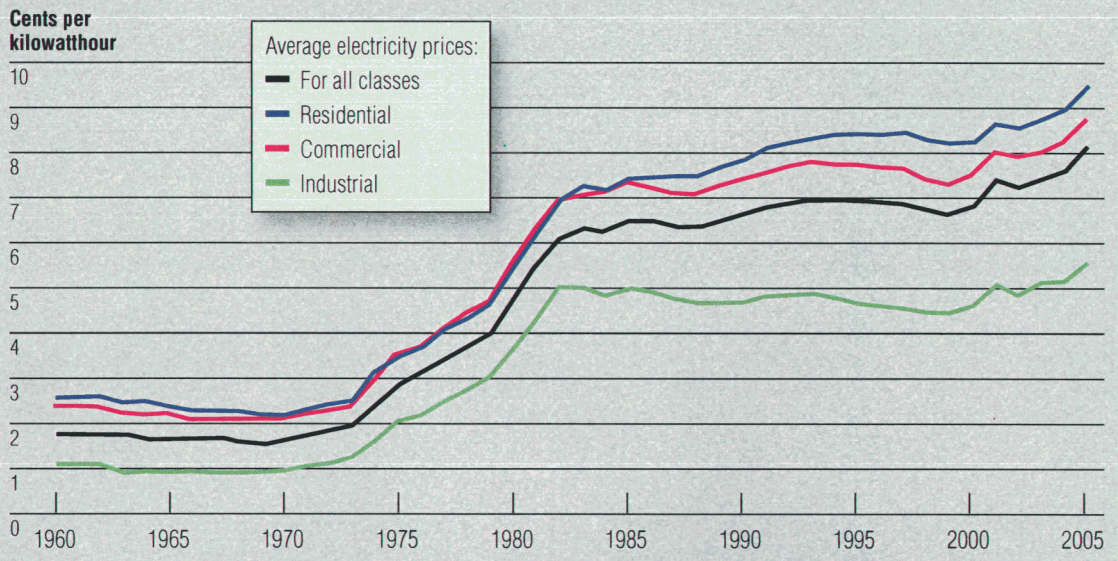
The 2000-2005 picture, however, shows electricity prices growing at a slightly greater pace than that of all items in the CPI. But even in this period, other products are growing much more rapidly. (See Figure 11.) Medical care and natural gas, for example, have both risen much faster than either electricity or gasoline and consistently faster than the rate of inflation. Like gasoline, electricity has at times risen faster or slower than the CPI.

Although changes in electricity prices in the United States have always reflected changes in underlying cost drivers to some extent, the mechanisms by which operating costs and investments in infrastructure enter into rates have become more complex and varied in the past decade. This is a result of regional and state differences in rate regulation, wholesale market organization, generation mix, and the individual characteristics of electric companies themselves such as their reliance on owned generation or purchased power to serve load. The degree to which rising fuel costs translate into wholesale power cost increases also varies substantially in regions with different market organization and generation mix. In short, there is no one price adjustment mechanism that applies universally to all regions, utilities, or their customers.



This situation has created widespread confusion for both regulators and consumers as both the level and timing of rate increases vary substantially from region to region. In some areas of the country,

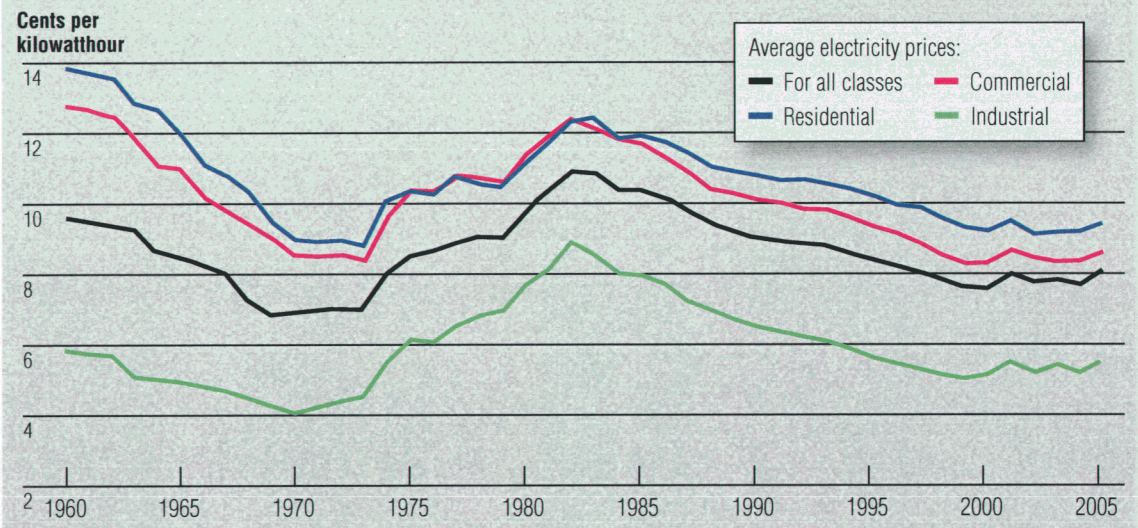
FIGURE 9
U.S. NOMINAL ELECTRIC PRICES BY CUSTOMER CLASS, 1960-2005



Source: EIA

FIGURE 10

U.S. REAL ELECTRIC PRICES BY CUSTOMER CLASS, 1960-2005
(2005 $)



Source: EIA

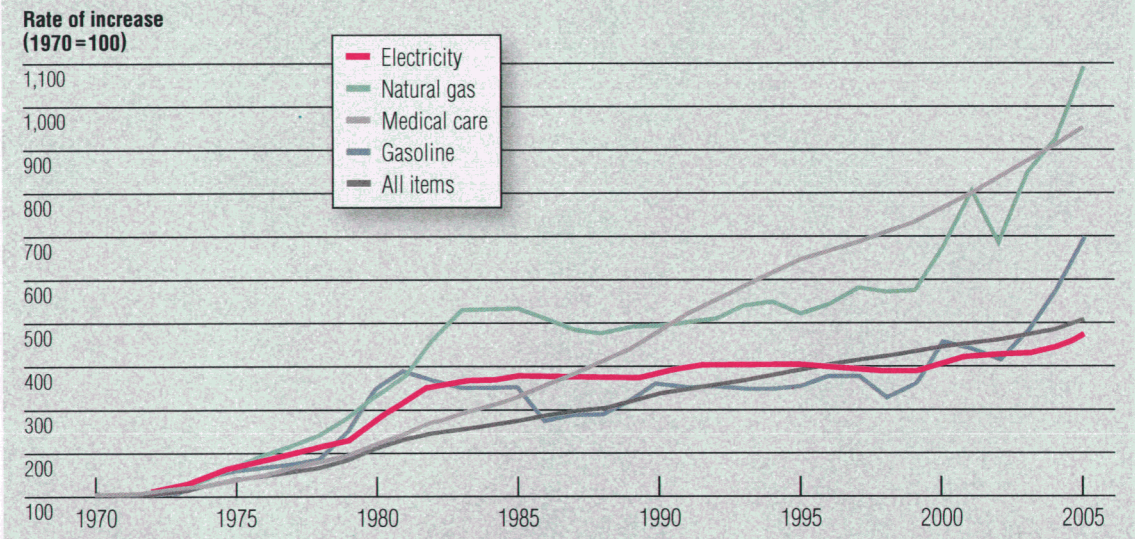
customers are still protected by rate caps instituted during the 1990s and have seen little of the increased fuel or purchased power costs reflected in their bills. In other areas, rate caps recently have expired, and sharply increased fuel and purchased power costs have led to substantial rate increases. In states where regulated retail utilities operate with fuel adjustment clauses (which translate rising fuel and purchased power costs into rates), customers have experienced increased rates and are bracing for more adjustments. Despite the variation in experience, it is clear that the fundamental cost driver of increased fuel prices ultimately will increase rates across the country and that the character of the rate increases will have a substantial impact on the ability of utilities to pursue needed investment priorities.

The High Costs of Inaction

Without going into the particular mechanisms by which rates can and will rise, it is important to understand the role of rates in the overall financial picture of retail electricity providers. Among other objectives, retail rates must cover operating costs and maintain the financial integrity of utilities in order for them to pursue needed investments, the benefits of which ultimately flow to customers and society at large. Properly designed and implemented, rates can also help utilities and customers improve resource allocation.

FIGURE 11

ELECTRICITY AND OTHER CONSUMER PRICE TRENDS, 1970-2005



Source: EIA, Bureau of Labor Statistics

Household Power Use

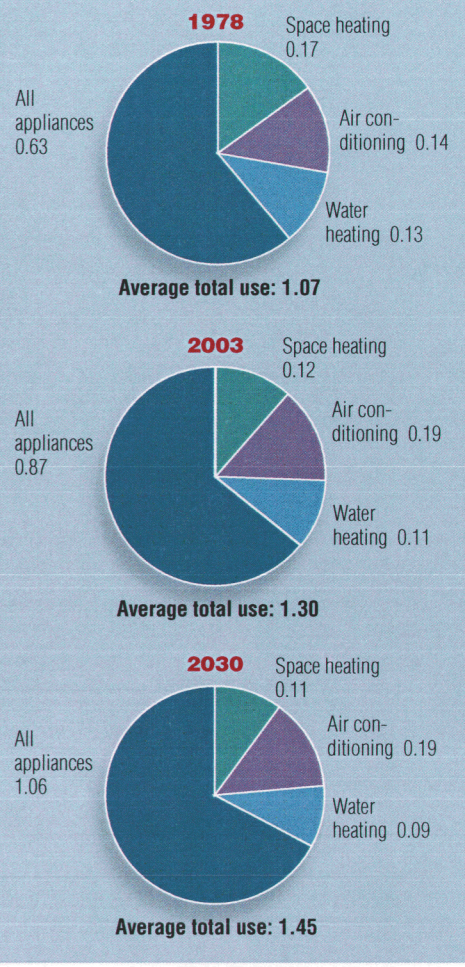
In 1978, more than 15 percent of a typical household's electricity consumption was devoted to space heating. (See Figure 1.) Another 12 percent went to water heating. By 2003, average household electricity consumption increased 21.5 percent, from 1.07 kilowatts per hour to 1.30 KW/hour. The percentage of electricity devoted to space heating and water heating declined, while the portion of electricity devoted to appliances and air conditioning increased. These changes are the result of several factors, with the most notable being the growth of personal digital appliances, such as computers, along with increased market penetration of air conditioners and many other electric appliances.

By 2030, average household consumption is expected to increase by another 11.5 percent, to 1.45 KW/hour. Appliance-related consumption will drive this increase entirely, largely reflecting the increased penetration of computers and other digital technologies. The amount of electricity needed to heat water and living space, along with the need for refrigeration and clothes washing, is expected to decline slightly as these technologies become more efficient over time.

Greater demand for electric power, however, does not translate directly into higher household expenditures. The average American household's total spending on electricity has fallen and is expected to continue to fall. Average annual expenditures on electricity fell from 2.9 percent of total expenditures in 1984, to 2.7 percent in 1994, and to 2.5 percent in 2004.

This rate of spending has been lower than the other major categories of consumer expenditures. Spending on housing, health care, and insurance premiums has more than doubled over the 1984-2004 time period; nominal (non-inflation-adjusted) spending on electricity increased by 69 percent. Since the price of all goods rose more than 82 percent during this period, inflation-adjusted household spending on electric power *declined*.

FIGURE 1
ELECTRICITY USE IN A TYPICAL U.S. HOME
(kilowatts per hour per household)



An important aspect of adequate rates is that they can lower the cost of capital for utilities. This means that the company can make investments for reliability, power quality, generation capacity, or environmental performance at reasonable costs—and thus help mitigate future rate increases. In contrast, rates that compromise current operating cost recovery without adequate prospects of adjustments will raise the cost of capital and inhibit investment that can yield long-term benefits.

The tension between near-term rate increases and the ability of utilities to invest in infrastructure to help alleviate those cost increases in the long term is inherent in regulation. However, it is worthwhile to point out that substantial benefits will occur if utilities can make the requisite investments in infrastructure improvements:

- *Long-run reductions in operating costs* that would accompany investments in economic baseload capacity, expanded transmission capability, and new distribution-level investments.
- *Enhancements of reliability and power quality* that would reduce the costs of power interruptions and promote productivity based on the continuing penetration of digital equipment that requires highly reliable service.
- *Improvements in competitive power markets* that would occur as transmission investments enable more fluid and liquid wholesale power markets over broader geographic areas.
- *Cleaner generation* from advanced coal, nuclear, and renewable power sources, which also will reduce the costs of meeting potential future greenhouse gas mandates.
- *Increased customer choice and control* over energy use arising from investments that enable innovative rate designs, distributed generation, and technologies to enhance the connection between retail customers and wholesale power markets.

A backlash against rising rates could imperil such benefits and lead to inadequate rate adjustments and an eroded ability of utilities to pursue improvements. While the near-term choices are often stark and unpleasant, the benefits from prudent utility investment have not diminished in this era of high fuel costs and rising costs of capital. On the contrary, the costs of inaction and capital investment atrophy are large and growing. ◆

To read the
Brattle Group's
full report,
"Why Are Electricity
Prices Increasing?
An Industry-Wide
Perspective," visit
www.eei.org.

Telecommunications • Litigation • Finance • Environment • Energy

Transforming America's Power Industry: The Investment Challenge

Preliminary Findings

Peter S. Fox-Penner
Marc W. Chupka
Robert L. Earle
The Brattle Group

Edison Foundation Conference
Keeping the Lights On: Our National Challenge
April 21, 2008

© 2008 *The Brattle Group*

Contents

- The Investment Challenge: Overview
- Drivers of Utility Cost Increases
- Investment Scenarios
- Generation Investment in Carbon Scenarios
- Investment Impacts of Enhanced Energy Efficiency
- Transmission and Distribution

© 2008 *The Brattle Group*

Power Industry Transformation

America's electric utilities are facing the greatest challenge in their history:

- Fuel costs remain at record-setting levels
- Plant construction costs have soared in the past several years
- Combating global climate change requires
  - "decarbonization" of supply
  - enhanced energy efficiency
- New technologies require a larger, "smarter" grid

© 2008 *The Brattle Group*

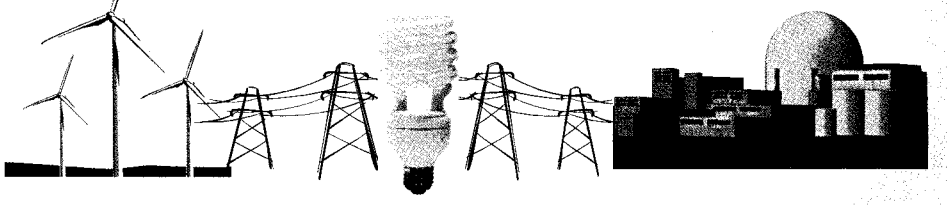
The American Power Industry: 20th vs. 21st Century

20th

- Economies of scale create ever-cheaper power
- Traditional fuels and sources
- Primarily supply-focused
- Passive "one-way" grid

21st

- Cost of key materials and fuels increasing costs for all parts of the industry
- Cleaner supply technologies and greatly reduced carbon emissions
- Energy efficiency and demand response critical for customer value, reliability, and environment
- Transformation to "Smart" Power Grid



© 2008 *The Brattle Group*

The New Capital Investment Challenge – New Generation

- Even with substantial energy efficiency measures, new and replacement plant through 2030 is at least 150,000 MW at an approximate cost of $560 billion. Much of this will be new renewable power

- Global climate policies will increase overall cost of electricity supply, affect the mix of new capacity built and add to the capital cost of new capacity.

- More aggressive efficiency improvements and price effects can significantly reduce demand and new generating capacity builds – but overall capital needs may not decline in the same proportion

© 2008 *The Brattle Group*

The Investment Challenge – Transmission and Distribution

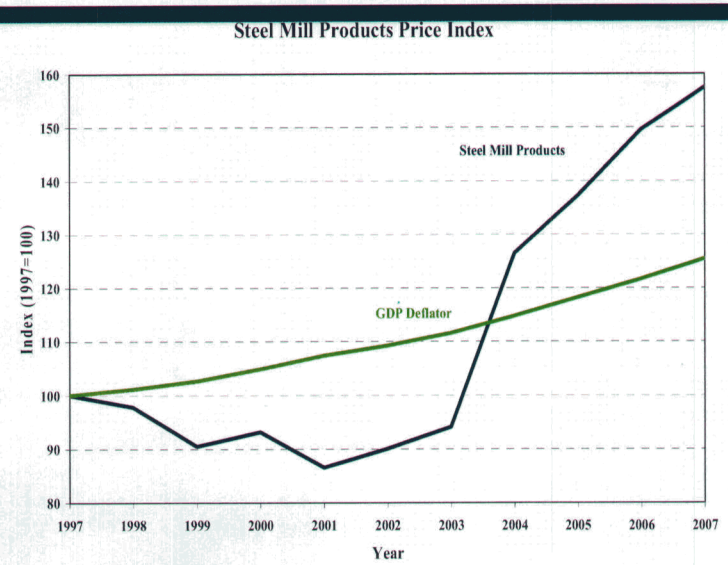
- Transmission and distribution together require nearly twice the investment in generation -- $900 billion by 2030
- Grid must be expanded to connect renewable and distributed sources
- "Smart Grid" technologies enable greater efficiency improvements, better service, and small-scale resources
- Plug-in hybrid vehicles create a large new grid use

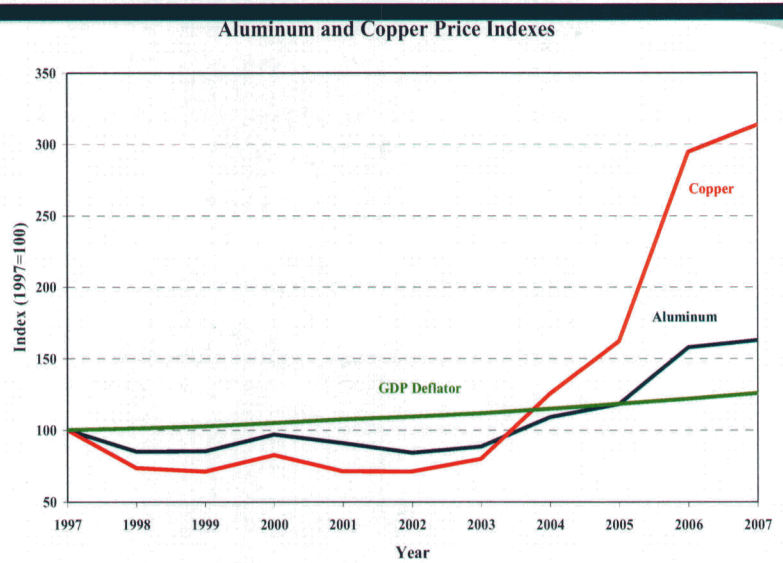
© 2008 *The Brattle Group*

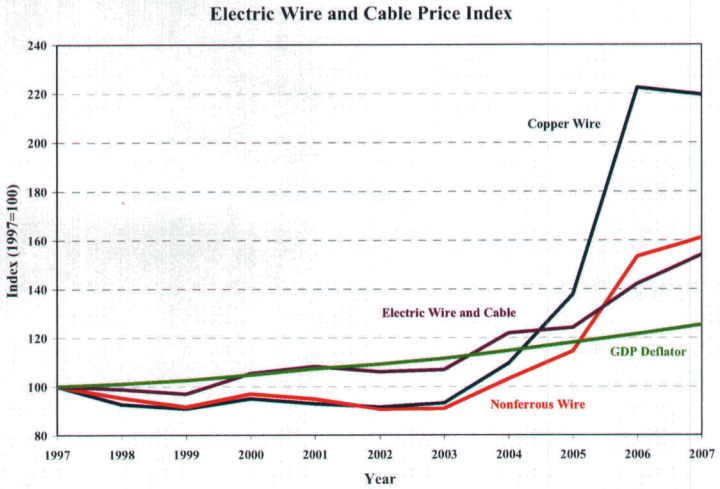
Drivers of Utility Cost Increases

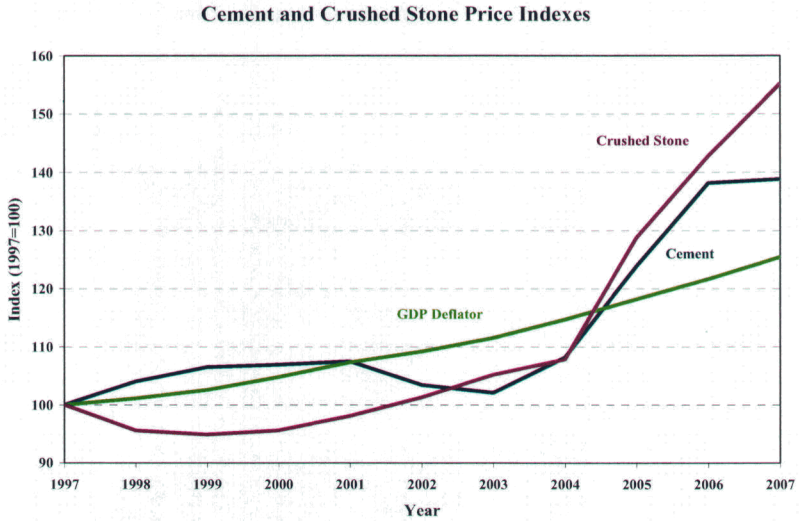
© 2008 *The Brattle Group*

Commodity Prices Continue to Rise



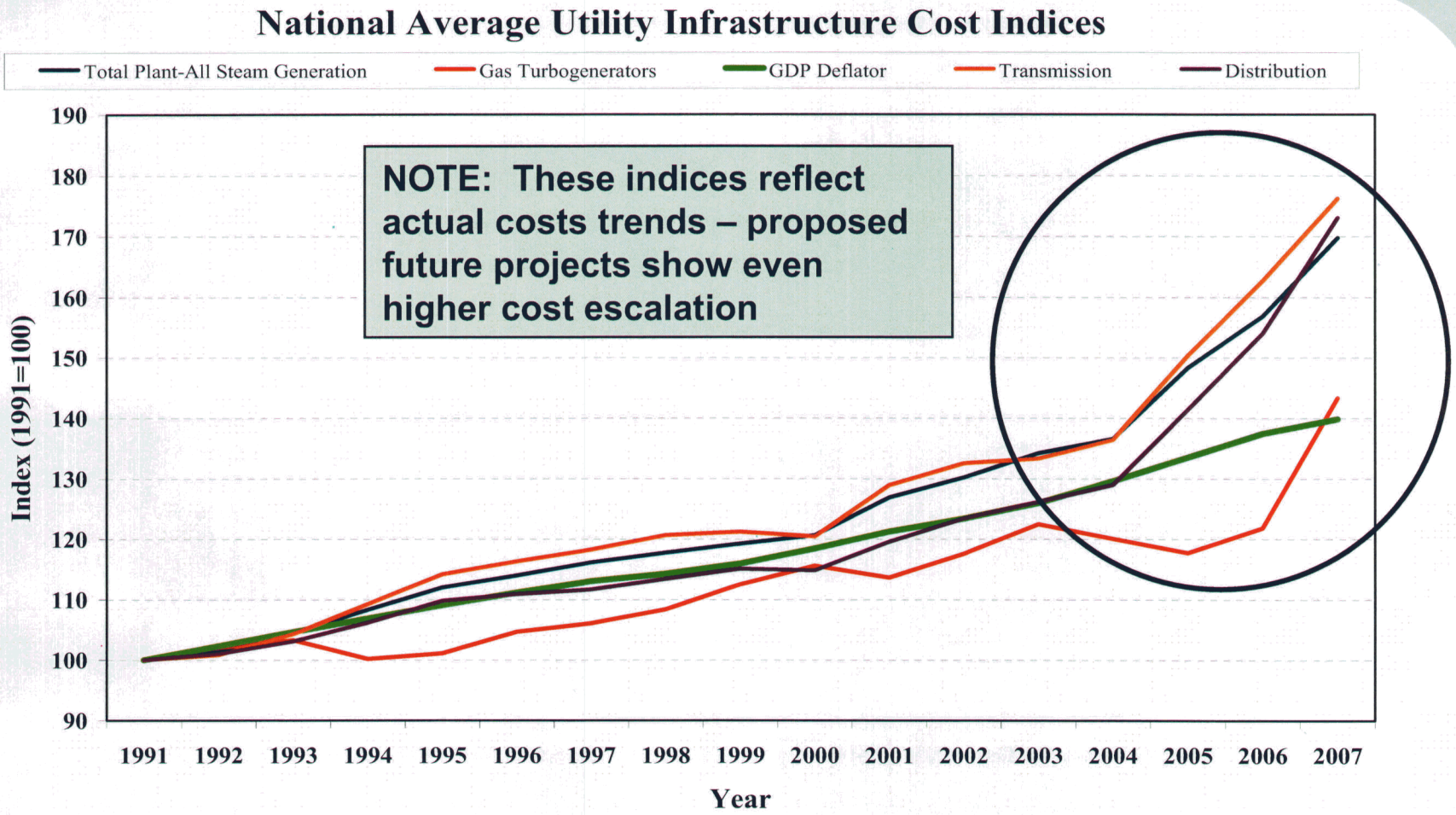






© 2008 *The Brattle Group*

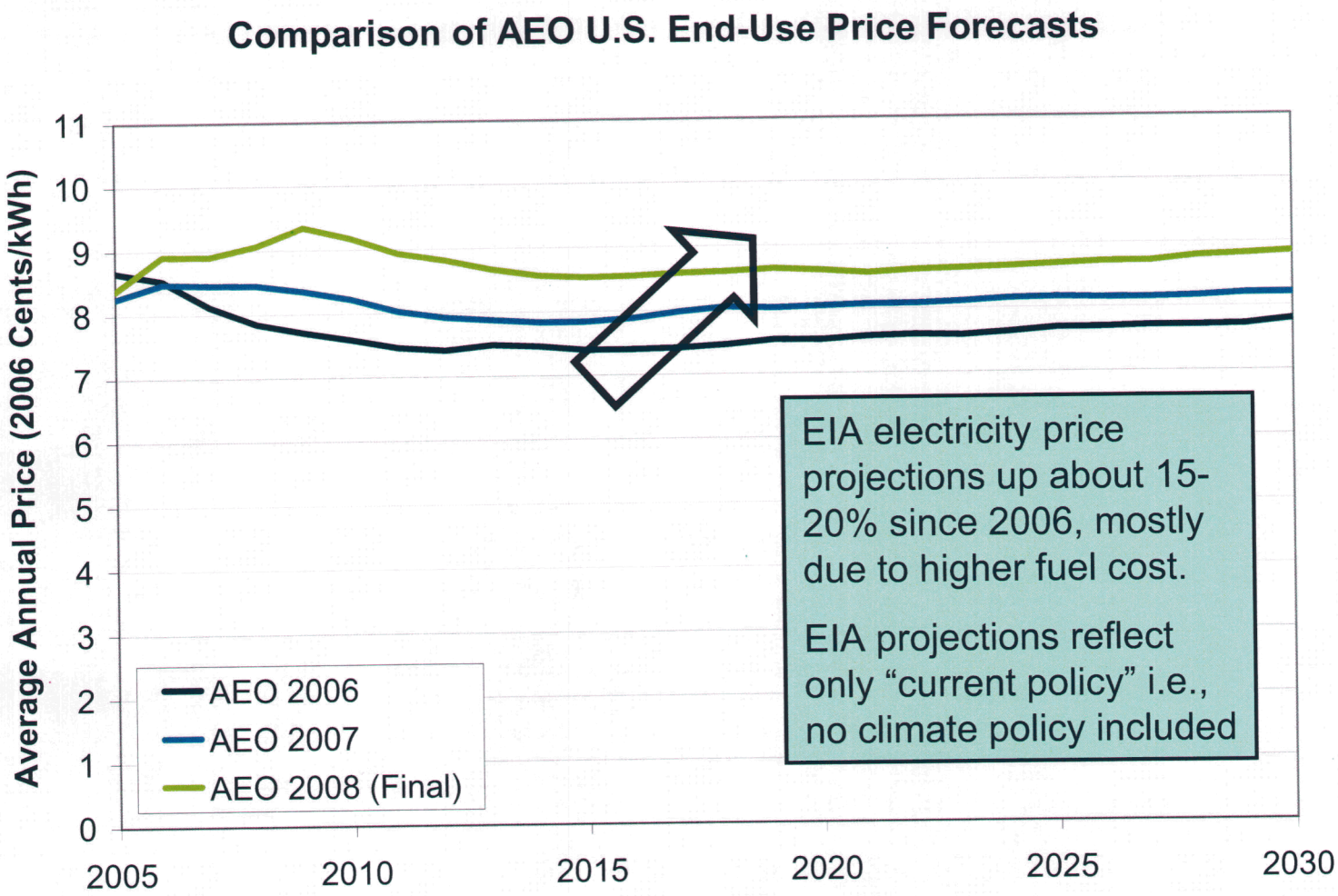
Utility Construction Costs Also Rising



Source: The Handy-Whitman© Bulletin, No. 165 and the Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

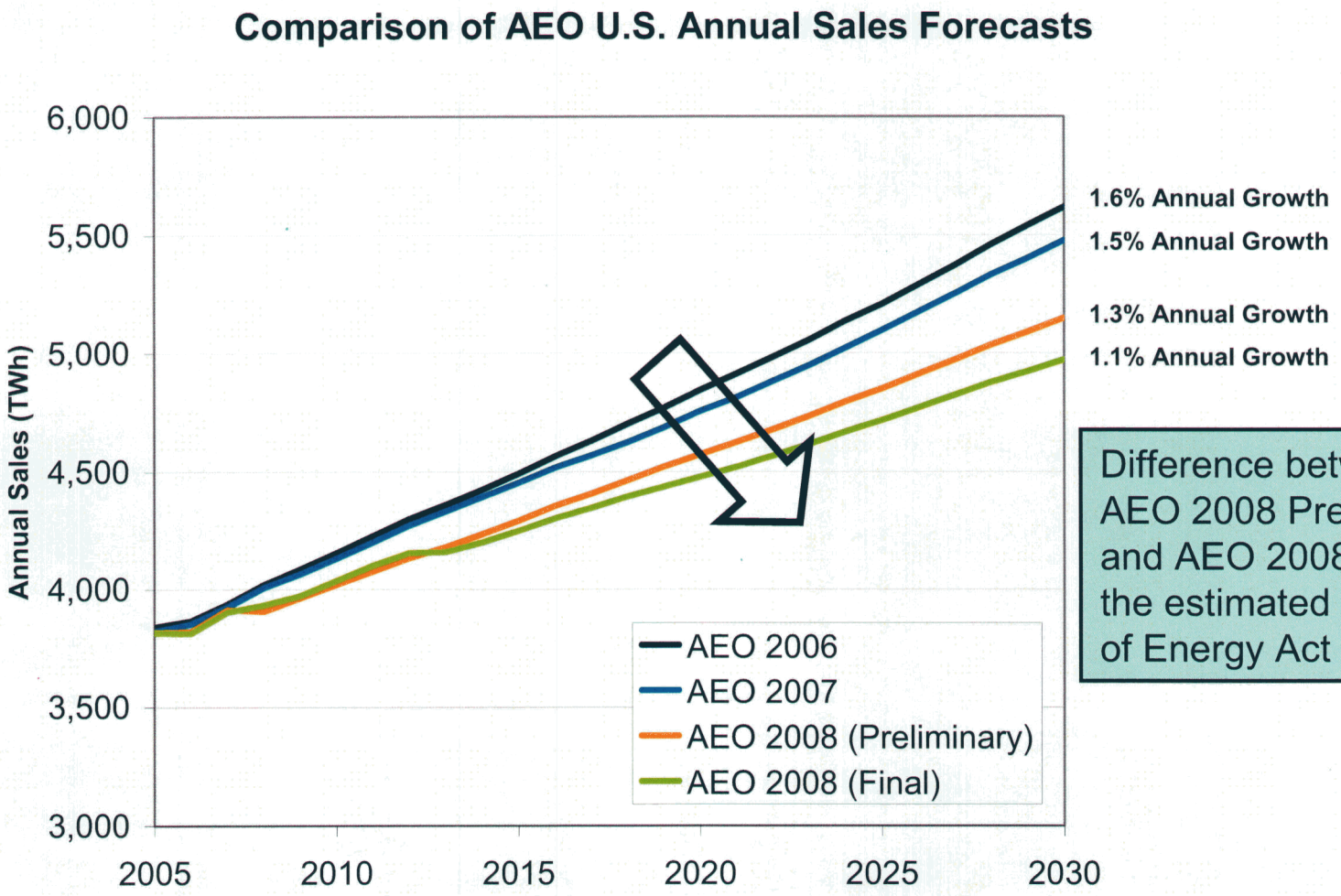
© 2008 *The Brattle Group*

EIA Price Projections Rising Over Time



© 2008 *The Brattle Group*

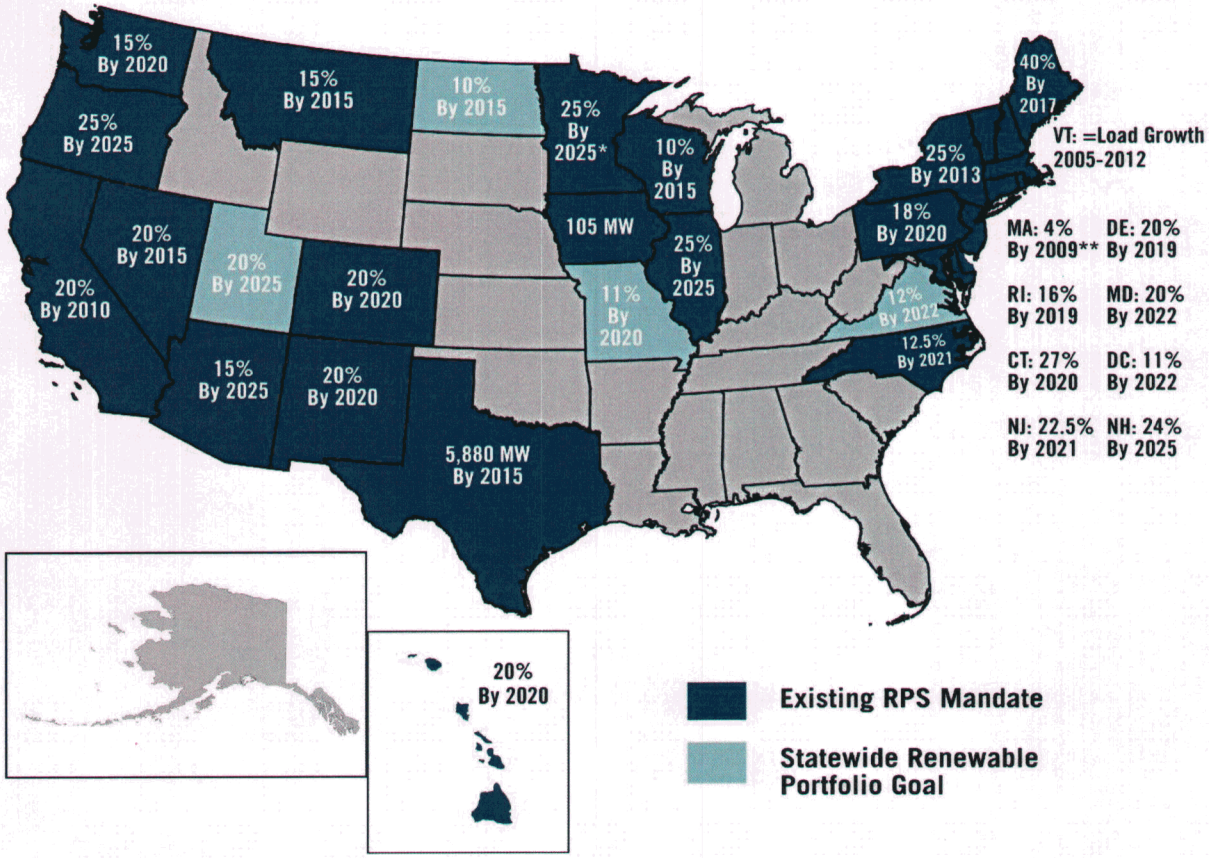
EIA Sales Forecasts Falling



Difference between AEO 2008 Preliminary and AEO 2008 Final is the estimated impact of Energy Act of 2007

© 2008 *The Brattle Group*

Renewable Standards Ratcheting Up



*Xcel Energy: 30% By 2020 **Increasing 1% per year there-after

Source: Edison Electric Institute, status as of April 8, 2008.

© 2008 by the Edison Electric Institute. All rights reserved.

NOTE: The renewable standards rise rapidly over the next decade.

Renewable generation capacity will have to be built to meet these standards regardless of load growth or regional reserve margins.

Investment Scenarios

© 2008 *The Brattle Group*

An Illustrative Carbon Policy Scenario

Two simplified carbon policy scenarios presented:

- No change from present U.S. carbon policies (EIA assumption)
- Replace all new conventional coal builds with Advanced Coal Technology (ACT) w/carbon capture & storage (CCS)

Our illustrative "Replace with ACT" carbon scenario estimates new plant investment impacts only – it is not an integrated climate policy analysis that account for all costs

- Only consider "first-order" impact on new capacity cost
- Demand response and fuel price substitution effects are not reflected in these estimates

© 2008 *The Brattle Group*

Impacts of Two Enhanced Energy Efficiency Cases Considered (Based on EPRI/EEI Study)

Realistic Achievable Potential (RAP):

- Most likely impact of expanded energy efficiency programs
  - Forecast of moderate customer changes and penetration rates of existing efficient technologies
  - Accounts for existing market, financial, political & regulatory barriers – but not full price effects

Maximum Achievable Potential (MAP):

- Higher-end of potential impact of cost-effective energy efficiency programs
  - Accounts for customer preferences and budget constraints
  - An aggressive but feasible customer participation rate

© 2008 *The Brattle Group*

Generation Impacts Analyzed Using *Brattle's* RECAP Model

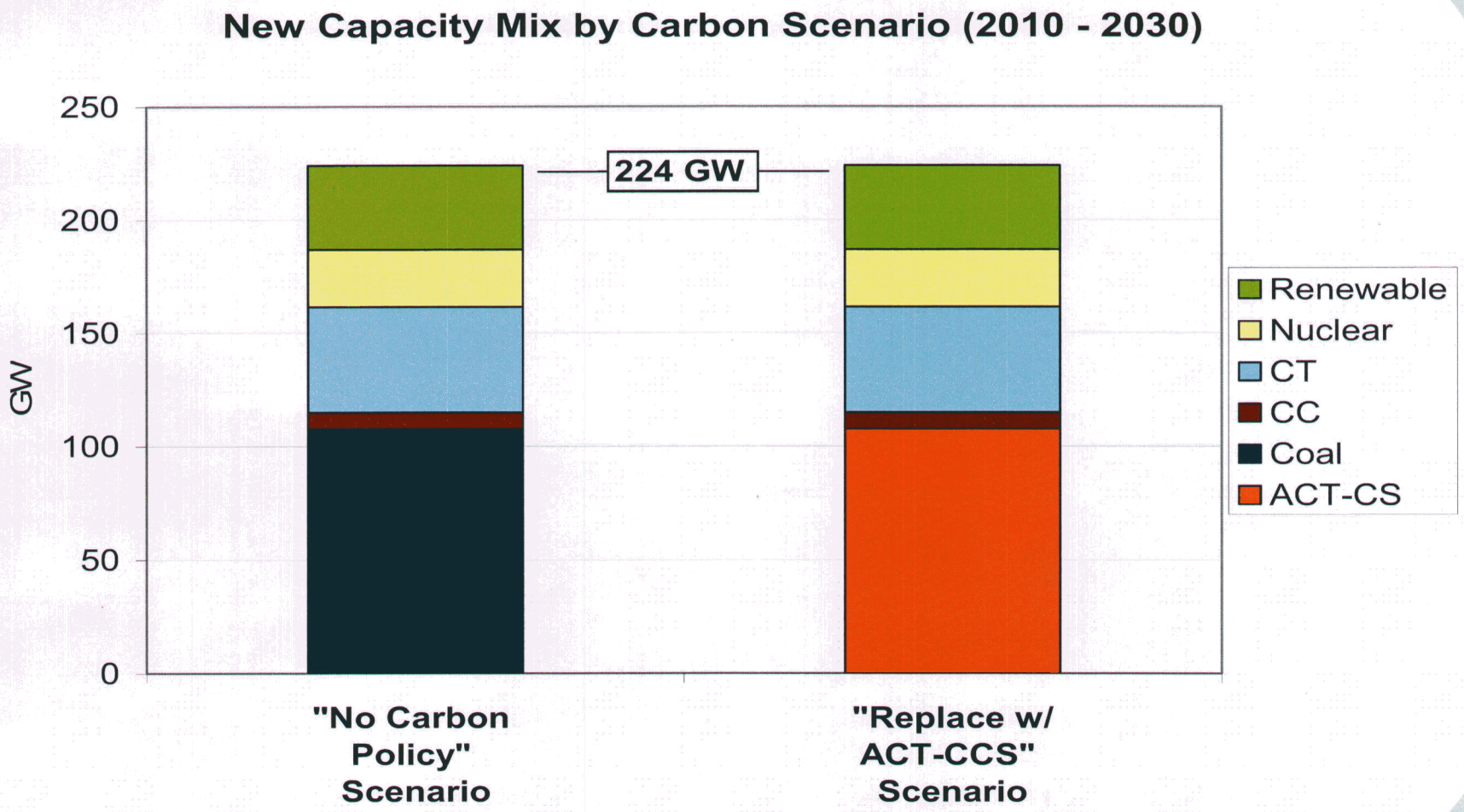
- The *Brattle* Regional Capacity (RECAP) model was used to project capacity additions and costs
- RECAP model results calibrate closely to the EIA Annual Energy Outlook (AEO) capacity additions when using AEO assumptions (fuel prices, demand growth, no carbon policies)
  - We assume higher construction costs than EIA, implying higher future customer rates
  - We also assume state-level Renewable Portfolio Standards (RPS) are met, also adding rate pressure
  - Full price feedbacks are not yet included, overstating sales growth

© 2008 *The Brattle Group*

Generation Investments by Carbon Scenario

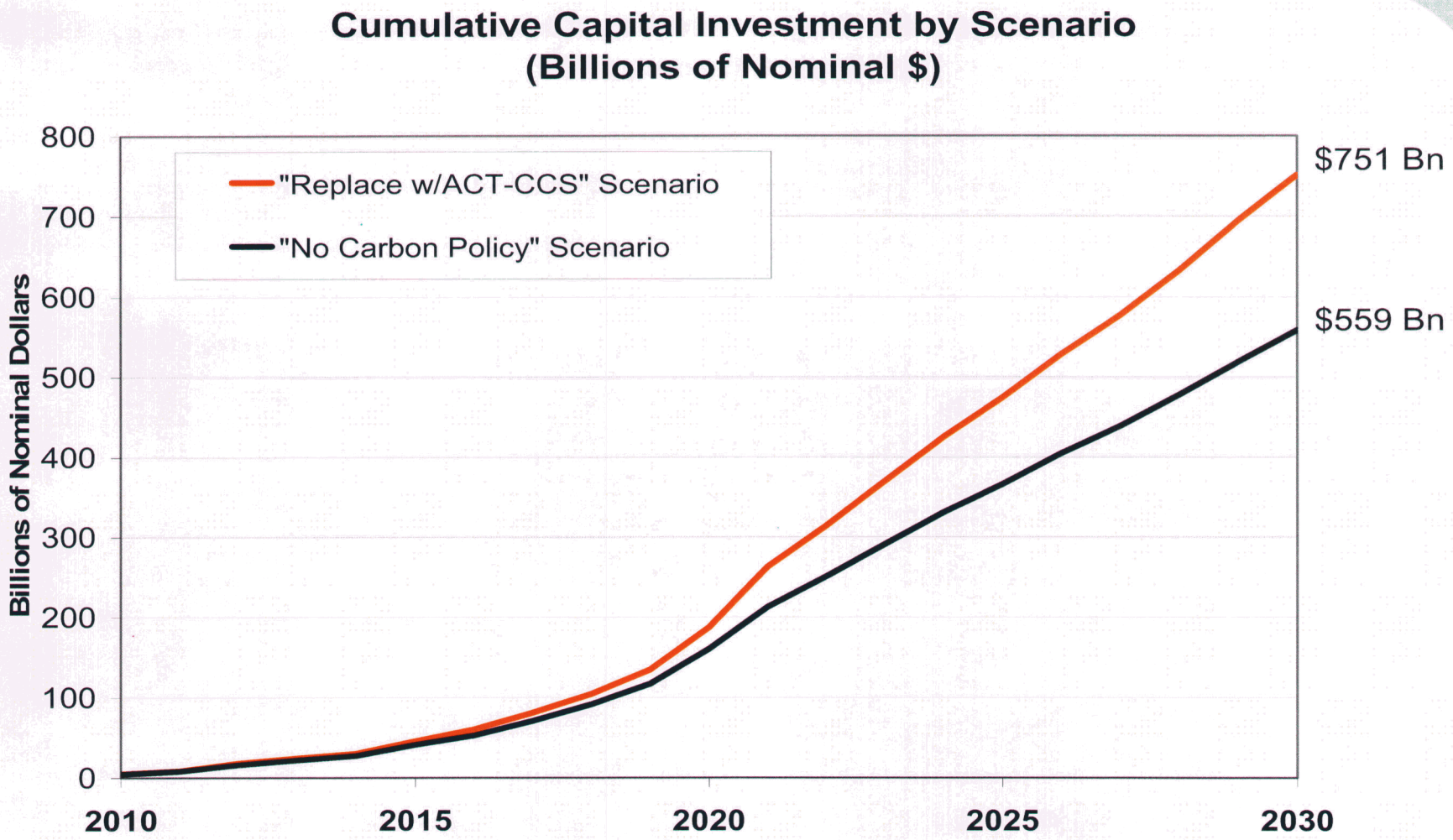
© 2008 *The Brattle Group*

Assumed Impact of Carbon Policy on Capacity Mix



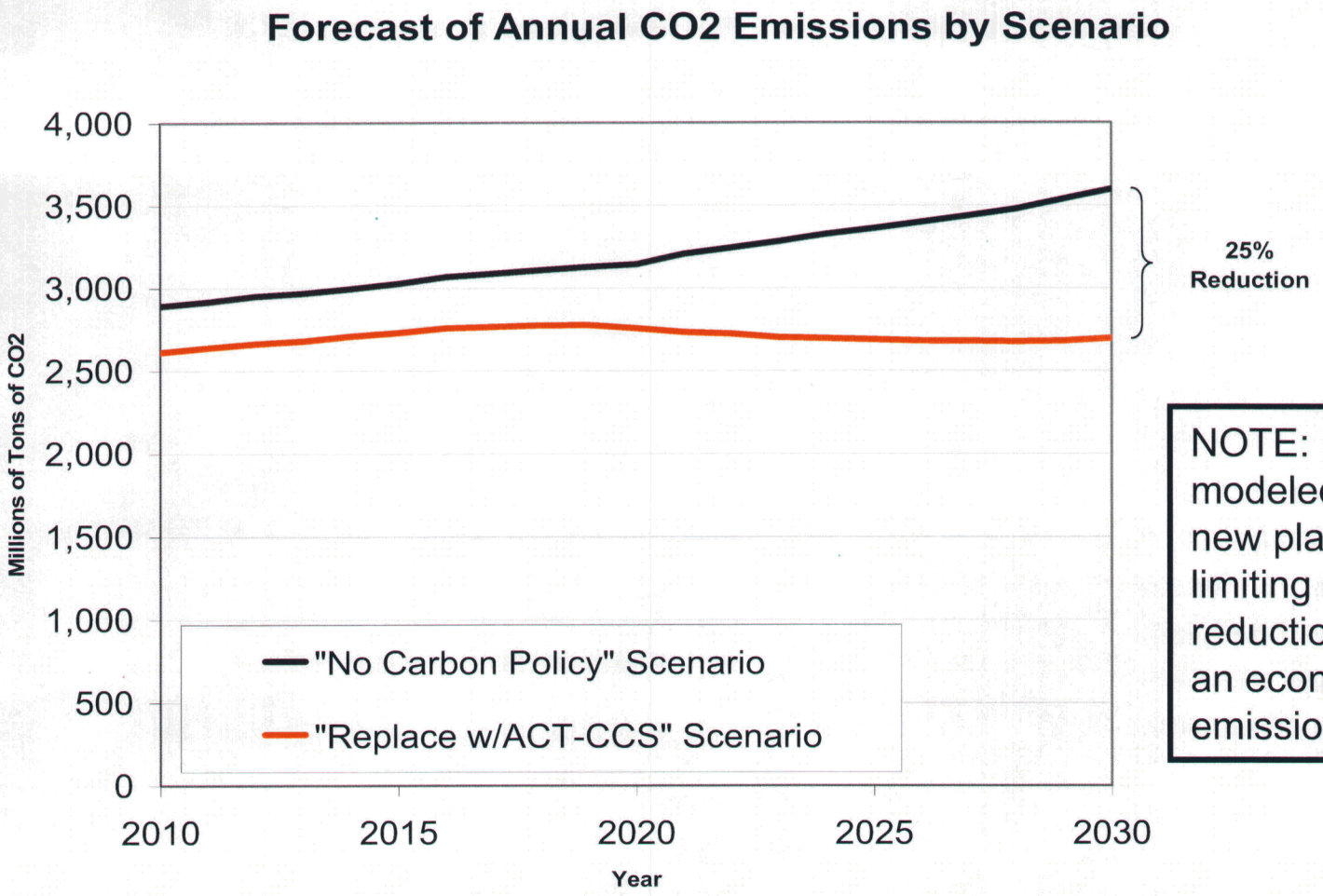
© 2008 *The Brattle Group*

Capital Investment 2010-2030 is $190 Billion Higher in the ACT-CCS Scenario



© 2008 *The Brattle Group*

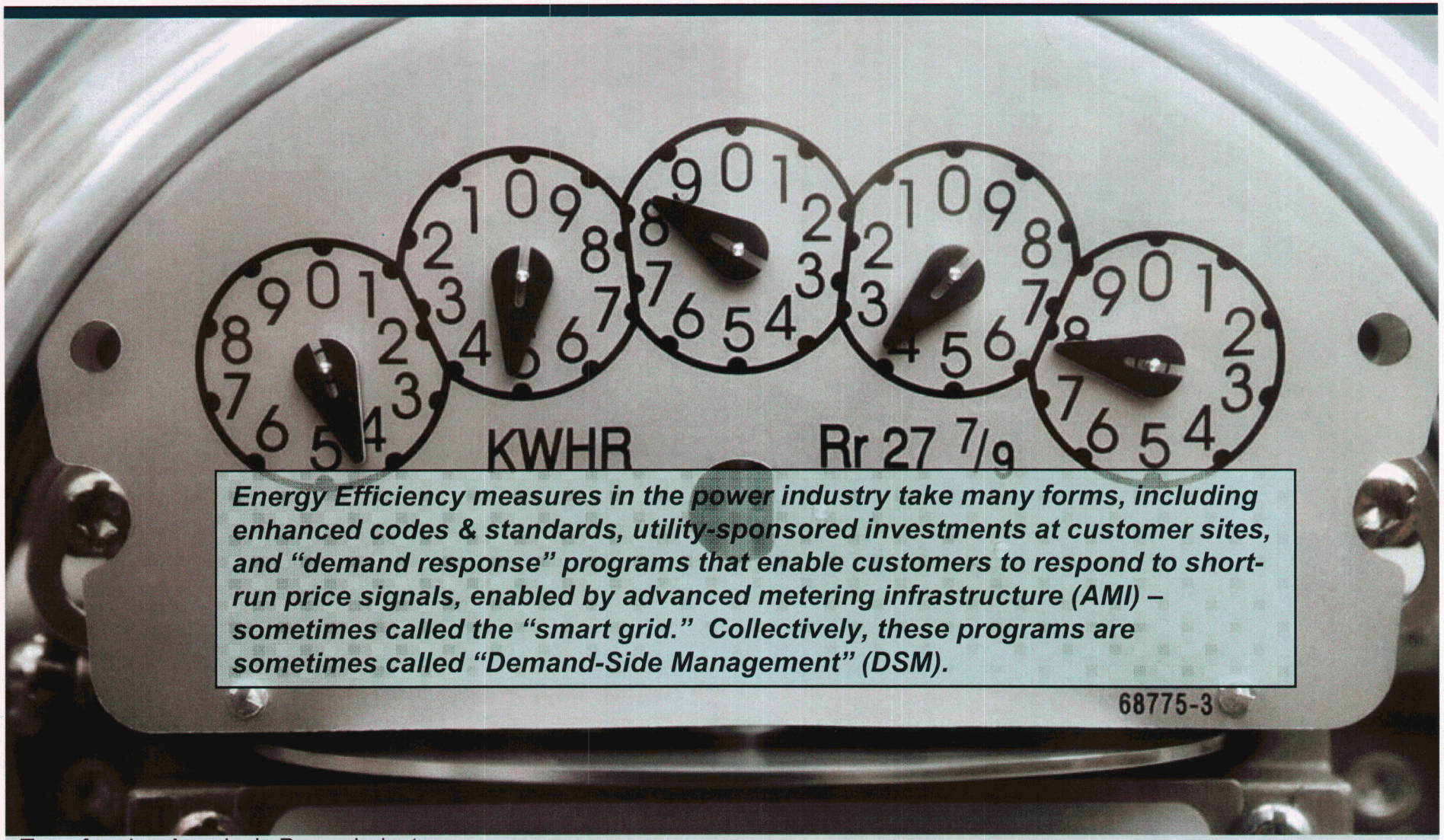
Electricity CO_2 Emissions Reduced by 25% in 2030 Under Assumed ACT-CCS Carbon Policy



NOTE: the CO_2 policy modeled only affects new plant construction, limiting overall CO_2 reductions compared to an economy-wide emission cap policy.

© 2008 *The Brattle Group*

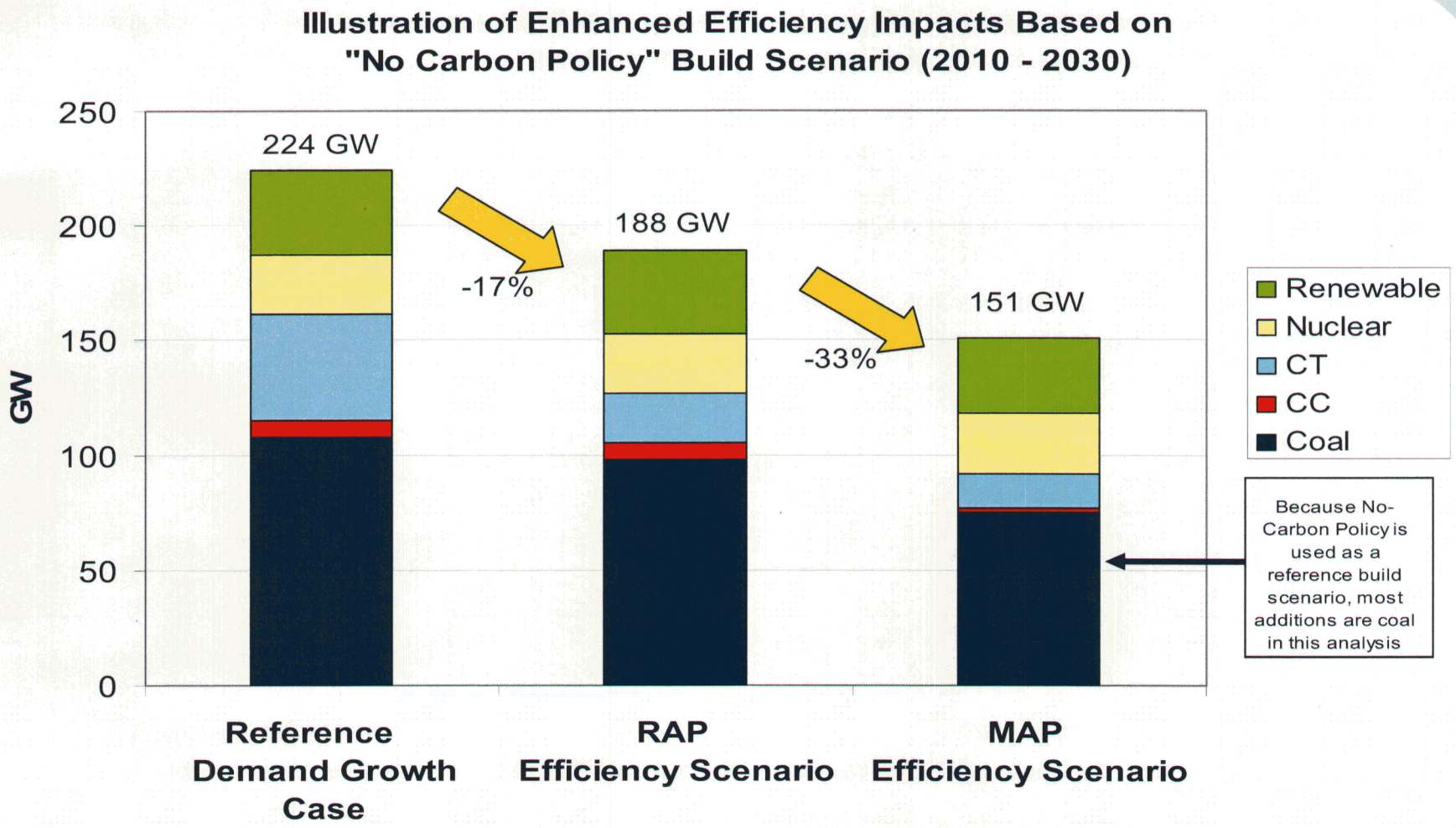
Investment Impact of Enhanced Energy Efficiency Measures



Energy Efficiency measures in the power industry take many forms, including enhanced codes & standards, utility-sponsored investments at customer sites, and "demand response" programs that enable customers to respond to short-run price signals, enabled by advanced metering infrastructure (AMI) – sometimes called the "smart grid." Collectively, these programs are sometimes called "Demand-Side Management" (DSM).

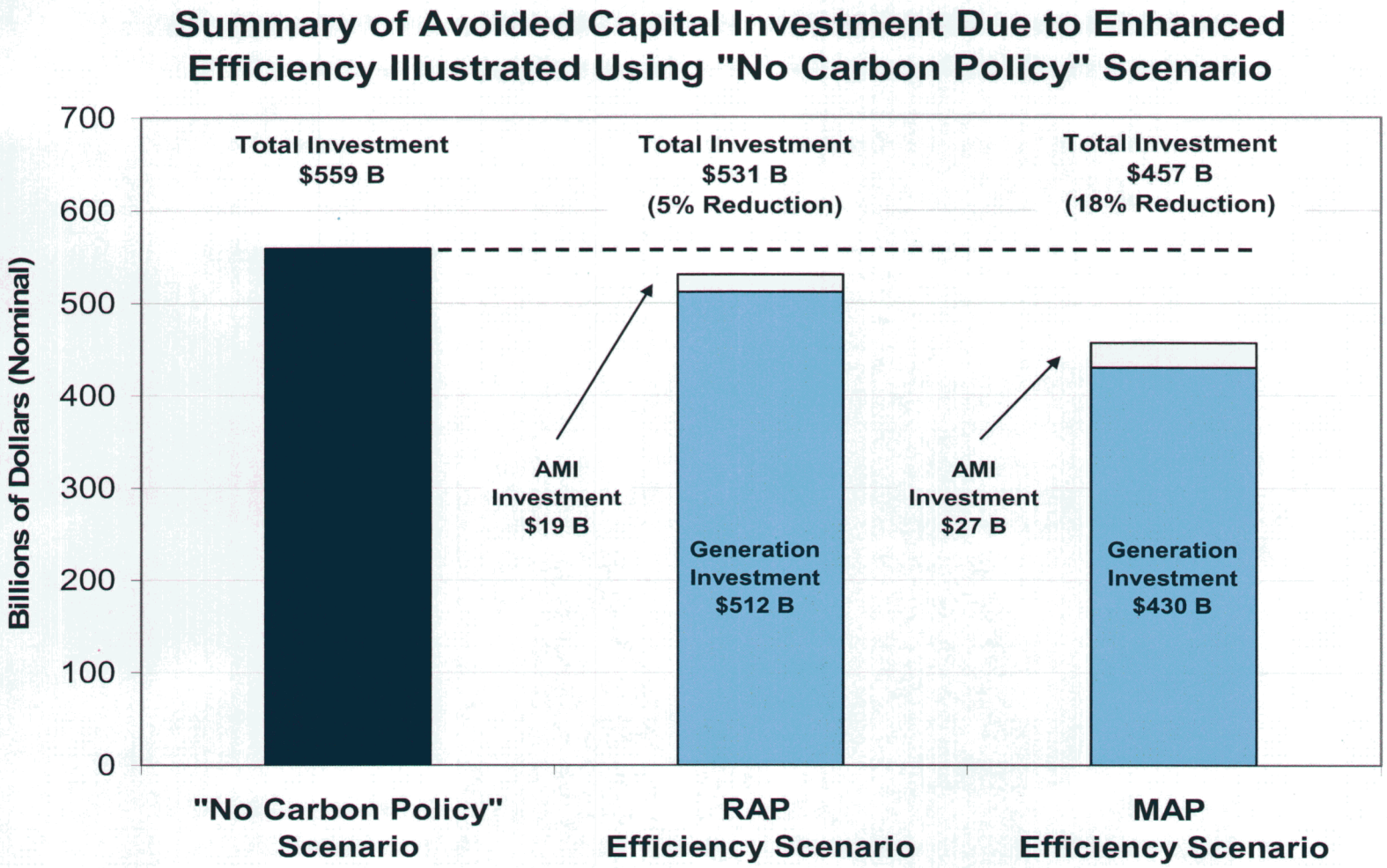
© 2008 *The Brattle Group*

Enhanced Efficiency Reduces Capacity Built by at Least 17-33%



© 2008 *The Brattle Group*

Enhanced Energy Efficiency Reduces Capital Investment to Meet Demand by 5% to 18% in 2030



© 2008 *The Brattle Group*

Capital Savings and Energy Efficiency Policies

- The percentage reduction in generation capital costs ($) is smaller than the reduction in new capacity builds (MW) in the enhanced energy efficiency scenarios:
  - Mostly peaking capacity avoided (*e.g.*, gas CTs), which have lower $/kW installation cost than coal or nuclear.
  - In RAP Scenario, new coal capacity decreases by 8% while peaking capacity decreases by 54%
  - In MAP Scenario, new coal capacity decreases by 30% while peaking capacity decreases by 68%
  - Mandated renewable investments largely unaffected, which are also more expensive than peaking units on a $/kW installed basis.
  - These impacts are a function of the assumed mix of enhanced energy efficiency measures that focus on demand response. Greater emphasis on overall energy saving measures would slow the rate of baseload plant additions but also increase energy efficiency investments
- Investment in AMI also offsets some of the capital savings in generating capacity
  - In RAP Scenario, AMI investment is 42% of avoided capacity cost
  - In MAP Scenario, AMI investment is 21% of avoided capacity cost
- Other efficiency investments may also be capitalized by the industry – these would add still more to the industry's capital needs.

© 2008 *The Brattle Group*

Transmission and Distribution

© 2008 *The Brattle Group*

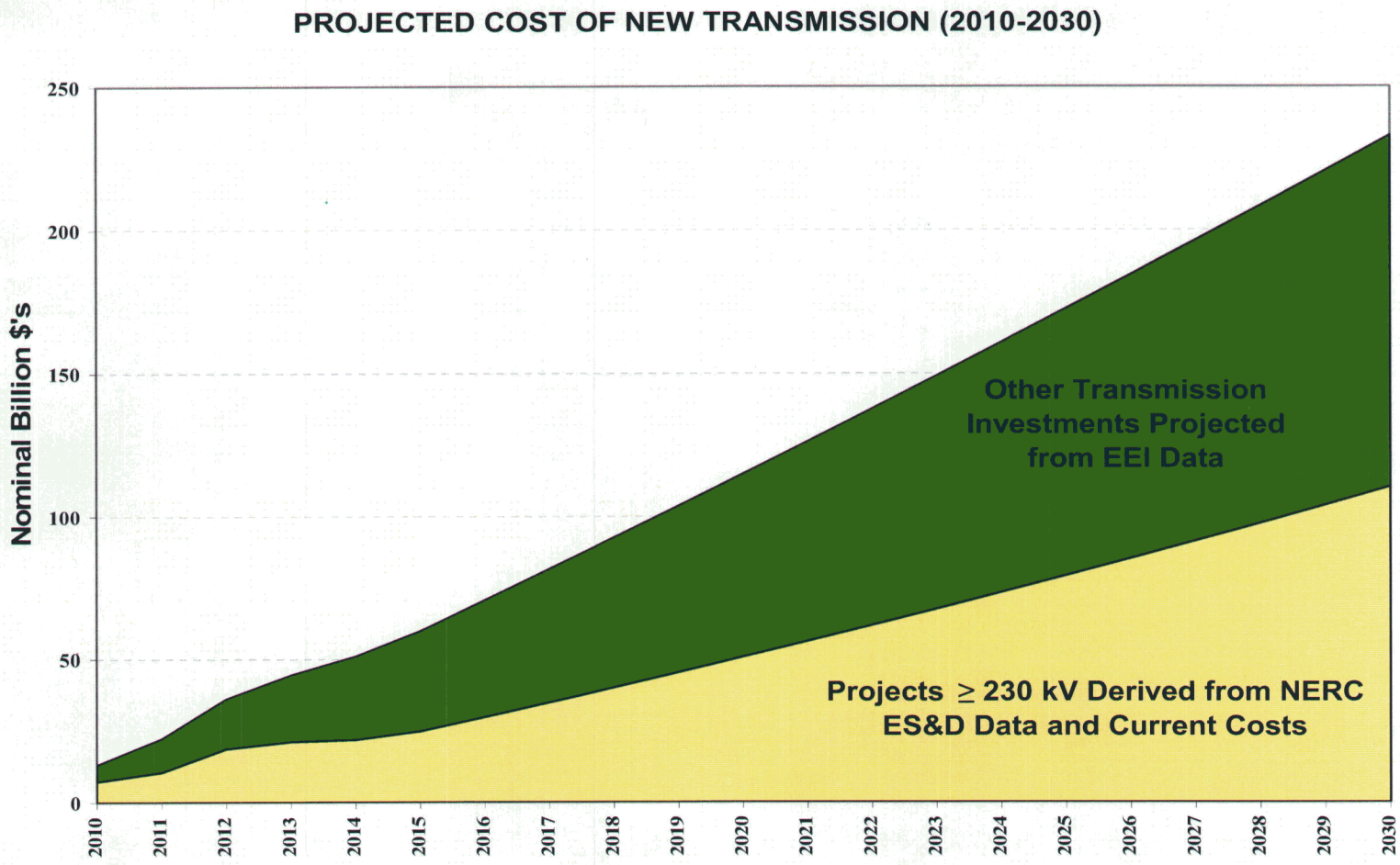
Transmission & Distribution Forecasts

The T&D forecasts 2010 – 2030 reflect only recent cost and expenditure trends

- Not a formal investment analysis of future needs
- **Near term transmission capital forecasts & data:**
  - NERC ES&D data on transmission project miles proposed to 2015 (by region, voltage classes ≥ 230 kV)
  - EEI member survey data on actual spending and planned expenditures ($) through 2010
  - Project costs ($/mile, $/MW-mile) from actual & proposed
- Historic distribution capital expenditures from EEI member survey data are only source for distribution

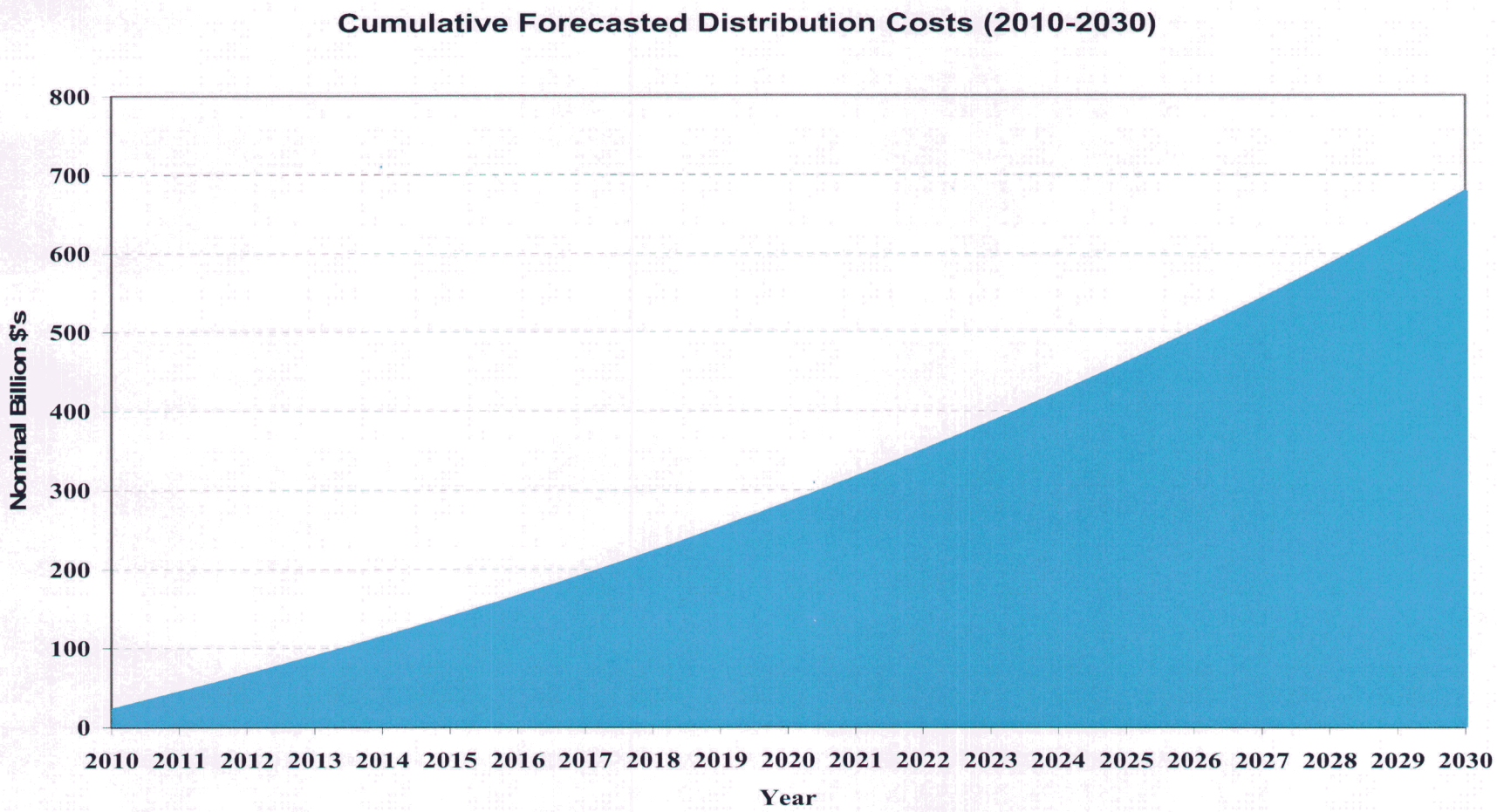
© 2008 *The Brattle Group*

Transmission Investments Could Reach $233 Billion 2010 - 2030



© 2008 *The Brattle Group*

Distribution Investments Could Reach $675 Billion 2010 – 2030



© 2008 *The Brattle Group*

Overall Study Results

Investment on the order of $1.5 trillion will be required over the 2010 – 2030 period

- Distribution - $675 billion
- Transmission - $233 billion
- Generation - $560 billion, with no changes in carbon policy

While enhanced energy efficiency measures will reduce sales growth and generating capacity needs substantially, <u>overall</u> capital requirements are less affected:

- Reduced peak demand tends to displace less expensive generation capacity
- Costs of energy efficiency measures add back significant cost

© 2008 *The Brattle Group*

Overall Study Results

Climate initiatives will add to new generation capital needs, in our illustrative carbon policy case:

- Use of Advanced Coal Technology with Carbon Capture and Storage could add about $200 billion in capital cost
- As applied to new capacity builds only, this hypothetical policy would reduce CO_2 from electric utilities by about 25% in 2030

© 2008 *The Brattle Group*

Arizona Public Service Company
Construction Expenditure Projection 2008 - 2010
$Millions

line	Production	2008	2009	2010	3- yr Total
	Nuclear (APS Share)				
1	Nuclear Fuel	93	117	110	320
2	Reactor Vessel Head, Units 1, 2, 3	9	13	5	27
3	Evap Pond & Reservoir Liner Replacement	9	15	8	32
4	Cooling Tower Replacement, Unit 1	1	7	19	27
5	Rapid Refueling Package	3	12	7	22
6	Other Nuclear Power Plant Improvements - Includes regulatory, safety, reliability, or efficiency projects not listed above	33	31	40	104
7	**Total Nuclear**	**148**	**195**	**189**	**532**
	Fossil & Hydro (APS Share)				
8	Cholla Environmental- Includes Baghouse, Scrubber, and other Environmental projects	91	67	55	213
9	Four Corners Environmental - Includes NOX abatement, particulate control, and other Environmental projects	10	9	6	25
10	Navajo Environmental - Includes NOX abatement and other Environmental projects	1	2	2	5
11	Other Coal Plant projects - Includes regulatory, safety, reliability, and efficiency projects at coal plants	53	53	51	157
12	Environmental Projects at Gas Plants	5	4	7	16
13	Long-Term Service Agreement Costs at Redhawk, West Phoenix	5	33	33	71
14	Yuma Peaking Plant	27	-	-	27
15	Other Gas & Hydro Plant projects - Includes capital costs for regulatory, safety, reliability, and efficiency projects at gas plants, and Childs/Irving Decomissioning	39	22	27	88
16	**Total Fossil & Hydro**	**231**	**190**	**181**	**602**
17	**Total Production**	**379**	**385**	**370**	**1,134**

Arizona Public Service Company
Construction Expenditure Projection 2008 - 2010
$Millions

line	Transmission & Distribution	2008	2009	2010	3- yr Total
	Transmission				
	Selected Major Transmission Projects				
18	Palo Verde - TS5 - TS9 TS5 to be located northwest of White Tanks; TS9 to be located near existing Raceway substation	55	48	30	133
19	TS5 - TS1 - Palm Valley TS1 to be located southwest of 195th Av & Deer Valley	12	17	6	35
20	TS9 - Pinnacle Peak 500kV	15	82	31	128
21	Palo Verde - North Gila 500kV	4	30	40	74
22	All Other Transmission Infrastructure Additions & Upgrades - includes Line & Substation additions & upgrades for 69kV and above voltage not listed above	96	105	143	344
23	Transmission Reliability Projects - Includes Breaker, Capacitor, and Reactor projects, and other major reliability projects	20	29	32	81
24	Transmission relocations & emergency projects	6	6	6	18
25	**Total Transmission**	**208**	**317**	**288**	**813**
	Distribution				
26	Distribution Infrastructure projects - includes Line & Substations additions & upgrades	95	59	57	211
27	Distribution Reliability Projects - includes projects for substation, overhead, and underground equipment	42	52	56	150
28	Other Distribution Projects - Safety, Relocation / Conversion, Emergency, and other projects	22	15	18	55
	New Customer Construction				-
29	Meters	29	32	32	93
30	Transformers	28	22	27	77
31	Service & Line Extensions	79	64	66	209
32	Street Light / Dusk-to-Dawn	4	4	4	12
33	**Total Distribution excluding Schedule 3 CIAC**	**299**	**248**	**260**	**807**
34	**Schedule 3 CIAC**	**(25)**	**(59)**	**(79)**	**(163)**
35	**Total Transmission & Distribution**	**482**	**506**	**469**	**1,457**

Arizona Public Service Company
Construction Expenditure Projection 2008 - 2010
$Millions

line	General Plant	2008	2009	2010	3- yr Total
36	Customer Service information systems	15	13	12	40
37	Distribution operations & work-management systems	19	17	21	57
38	All Other Info Sys Projects - includes infrastructure additions, equipment replacement, and all other Generation, T&D, and Shared Services systems & telecom	37	38	36	111
39	Deer Valley Operations Hub	38	63	18	119
40	Facilities - includes new service centers, upgrades of existing facilities, and replacements of mechanical equipment, plumbing, etc. at APS facilities.	47	59	61	167
41	Other General Plant	6	4	6	16
42	**Total General Plant**	**162**	**194**	**154**	**510**
43	**Total APS**	**1,023**	**1,085**	**993**	**3,101**

FitchRatings
KNOW YOUR RISK

Corporate Finance

Global Power
Criteria Report

Credit Rating Guidelines for Regulated Utility Companies

Analysts
Robert Hornick
+1 212 908-0523
robert.hornick@fitchratings.com

Ellen Lapson
+1 212 908-0504
ellen.lapson@fitchratings.com

Steve Durose
+61 2 8256 0307
steve.durose@fitchratings.com

Glen Grabelsky
+212 908-0577
glen.grabelsky@fitchratings.com

Sharon Bonelli
+212 908-0581
sharon.bonelli@fitchratings.com

Andrew Steel
+44 20 7862 4086
andrew.steel@fitchratings.com

Pekka Laitinen
+81 3 3288 2747
pekka.laitinen@fitchratings.com

Related Research

- Fitch's Approach to Rating Competitive Generators, July 24, 2007.
- Post-Maintenance Interest Coverage Ratios for UK Utilities, Feb. 28, 2007.
- Equity Credit for Hybrid and Other Capital Securities, Sept. 27, 2006.
- Operating Leases: Updated Implications for Lessees Credit, Dec. 20, 2006.
- Evaluating Liquidity in the Power and Gas Sector, Sept 1, 2005.
- Cash Flow Measure in Corporate Analysis, Oct. 12, 2005.

■ Overview

These guidelines are an overview of Fitch Ratings' global approach to credit ratings for electric, natural gas and water utilities. This report updates and replaces Fitch's previously published credit rating criteria for regulated electric distribution companies and also covers vertically integrated electric utilities, natural gas distribution companies and water companies. The report also incorporates Fitch's methodology for evaluating corporate liquidity. Since utilities are significantly affected by local and national laws and regulations as well as regional and local consumption patterns and energy economics, Fitch also publishes periodic reports that explain the application of these guidelines to specific markets in many parts of the world.

The rating evaluation of an electric, gas or water utility considers the qualitative and quantitative risks associated with the company's business and corporate structure in combination with the company's financial strength and liquidity. The financial assessment emphasizes cash flow financial measures rather than equity or earnings-based ratios. The analytical focus is on the adequacy of the utility's cash flow relative to fixed charges, debt obligations and capital expenditures as well as its capital structure, liquidity and profitability.

The assessment of operating and business risks is an important element in determining ratings. This analysis is carried out using both quantitative and qualitative methods. Qualitative factors with the most significant effect on companies in the utilities sector include an evaluation of the regulatory and political environment in which the utility operates, including such factors as price-setting and cost-recovery mechanisms, transparency and predictability of the regulatory regime, exposure to competition and the nature of the customer franchise. In addition, Fitch's operational and business evaluation considers the degree to which the utility bears financial exposure to variations in commodity costs and in the case of network businesses, the responsibility for reliable supply. The business risk profile is also influenced by factors such as customer demographics, the type and quality of assets, operating performance, fuel mix, exposure to hydrological risks and management's strategy and capability. Each of these factors will affect the predictability or volatility of a utility's cash flow.

The assessment of operating risk also includes a review of the historical volatility of operating cash flow, when available, compared to the historical trend of similar companies. Fitch analysts review past cash flow trends to assess how the volatility or stability has been affected by the aforementioned fundamental factors. The assessment incorporates analytical judgment about how fundamental factors may affect the company's future operating cash flow.

Another important step in the rating process is an assessment of the utility's legal and corporate structure. Fitch's analysis focuses on the extent to which the utility's rating is aided by the financial support of a parent, sovereign or subsovereign entity, insulated from other group members through ring-fencing mechanisms or burdened by the weak condition of its parent, subsidiaries or affiliates. This assessment can either raise or lower the rating that would otherwise result from the analysis of an entity's stand-alone financial condition and business risk position.

Because regulated utilities typically enjoy more stable and predictable cash flows than industries that are highly competitive, cyclical or with less predictable demand, utilities in favorable regulatory and legal jurisdictions have the ability to support increased leverage and enjoy higher ratings than industrial companies with similar financial metrics. Regulated utilities in developed nations generally merit issuer default ratings (IDR) in the investment-grade categories, typically ranging from 'AA–' to 'BBB–', but there is no global norm.

■ Regulated Utility Qualitative Risk Factors

While regulated utilities generally have more stable and predictable cash flows than companies in many other industries, it would be a mistake to view all regulated utilities as identically low-risk businesses. A number of credit concerns exist for regulated utilities, including:

Regulatory Risk

Among the largest risks of regulated utilities are unfavorable regulatory policy and unpredictable regulatory outcomes (lack of "transparency" in the regulatory process). If the jurisdiction's rate-setting climate is confiscatory or capricious, a utility cannot uproot its assets and move to a more attractive jurisdiction. A utility may be obliged to meet levels of service quality or specific investment levels that exceed the utility's financial capability or ability to attract capital. In mature markets, if the goal of the regulatory authority is to reduce end-user prices, utility tariffs may be ratcheted downward to the point that no further economies can be wrung out of the expense base and profit margins and financial protection measures are eroded as a result. Disallowing prudently incurred costs would cause similarly unfavorable results.

Commodity Price/Market Risk

Some utilities are exposed to significant commodity price risks, while others have access to hedging mechanisms, such as the ability to pass through to consumers changes in fuel or purchased power costs or in the case of some distribution/retail companies, the actual cost of supplying electricity or natural gas. This is a major variable in comparing the risk of electric and gas utilities. When commodity costs are rising, the frequency of fuel adjustments is particularly important. Utilities insulated from market price exposure will be able to carry more leverage at a particular credit rating level than those exposed to market price risk. However, in a high or rising commodity cost environment, even utilities that are able to recover commodity costs from end-use customers are subject to higher working capital requirements associated with regulatory lag, depressed customer demand and increased bad debt expense, which may not be recoverable in rates. Finally, utilities typically collect revenues in local currency, and emerging market utilities can be exposed to currency devaluation if they have fixed costs or debt in nonlocal currencies.

Operating Risk

For electric utilities, the threat of a prolonged unplanned outage of a key operating facility is a significant credit risk. If an electric generating unit is out of service for an extended period, replacement power costs could be significant, particularly during peak heating or cooling seasons. In the case of large coal- or nuclear-fueled base-load generating units, an outage could drive up regional power prices, exacerbating the higher cost of replacement power. Even for a company with an effective fuel-adjustment mechanism, regulatory lag can strain liquidity and/or regulators may disallow cost recovery if the outage is deemed to have been the result of imprudent behavior on the part of the operator. Base-load generating units that represent a significant concentration of a company's asset base pose the greatest risk. Extensive damage to a transmission or distribution network related to a storm or disaster may also result in temporary stress. The exposure is greatest for the rural or remote parts of a network system, particularly those in mountainous terrain that is difficult to access. Even if regulators permit cost recovery, some regulatory lag is likely. To a lesser extent, system damage is also an issue for natural gas utilities, most notably in storm or flood-prone regions. Depending on the regulatory regime, water utilities may face hydrological risks both in terms of the availability and price of bulk water purchased and volume risk associated with lower demand if water usage restrictions are required in times of drought.

Competition, Obsolescence and Technology Risk

In many jurisdictions, network utilities are granted an exclusive monopoly franchise to serve all needs of consumers within a geographical footprint. In some cases, consumers may have the option to switch their service to a competitor. Even where a utility holds an exclusive franchise to serve consumers, a substitute energy supply may compete directly (for example, natural gas delivered by pipes in competition with bottled gas, oil, kerosene or electricity). The more essential the service is to consumers and the less subject it is to competition, the more stable and secure the utility's business profile becomes.

Although not an immediate concern, long-term credit ratings of electric utilities should consider the exposure over the long term to technology risk. Potential competitors for electric service include on-site industrial generation, generation of electricity using microturbines or fuel cells, on-site solar or wind production of energy, or installation of more energy-efficient appliances or industrial processes. In most areas, significant bypass of the wired distribution network is not currently commercially feasible, although some new technologies are becoming economically competitive in remote areas and under special circumstances. Customers will have a greater economic motivation to invest in new equipment or alternate energy supplies if the regulated utility tariff is uneconomically high (e.g., a tariff that incorporates high competitive transition charges, cross-subsidies to another class of customers or subsidies for social welfare costs, such as universal service).

Mergers and Acquisitions

There are numerous examples of consolidation mergers that resulted in more efficient companies with stronger operating expertise and financial and capital resources. Conversely, consolidation often creates new credit risks, such as management distraction, difficulty in achieving expected synergies, inflated acquisition prices and increased financial leverage, unfavorable treatment by regulators and the credit risk of a combination with a financially weaker company.

■ Credit Rating Criteria for Utilities

Corporate/Legal Structure

The corporate structure of a utility can have a significant effect on credit ratings. In some cases, the utility may be a subsidiary of a parent holding company, with other subsidiaries engaged in a variety of businesses. In other cases, the utility is a parent, with subsidiaries or divisions engaged in competitive and nonregulated businesses. Fitch's analysis focuses on the extent to which the utility's rating is aided by the financial support of a parent or burdened by the weak condition of its parent, subsidiaries or affiliates.

Among the important considerations is the extent to which a utility's access to capital may be damaged by the financial difficulties of a parent or affiliate and/or whether the utility is dependent on the parent for equity to support capital expenditures. The analysis also considers whether the corporate parent relies on utility dividends to support other regulated or unregulated subsidiary operations. In cases that Fitch determines there is a significant business with financial or legal interdependence, the rating differential between a utility and its parent or a utility and its subsidiary is likely to be limited. If financing occurs at the parent for all entities, or where significant cross-subsidies between the utility and its affiliates occurs, a consolidated rating is likely.

The legal analysis considers national laws that vary among countries and define the extent to which parents may be held responsible for the debt of subsidiaries or circumstances in which subsidiaries are responsible for the liabilities of a parent or affiliate. Public service entities may be subject to normal credit rights and bankruptcy laws, as is the case in the United States, or exempt from foreclosure or normal creditor remedies. In some jurisdictions, such as the UK, the government may have the right to impose a special administrator, whose principal responsibilities may be more closely aligned to ensuring continuity of supply rather than ensuring maximum recovery for creditors. Fitch considers these legal and structural issues to determine to what degree a utility's rating is affected by the credit quality of its parent or affiliate.

Statutes, regulatory laws or terms of the utility concession may restrict transactions between a utility and its corporate parent (or subsidiaries or affiliates), limit the maximum amount of debt permitted to be owed by the utility and control the amount of dividends and distributions from the utility. Similar restrictions may be contained in bond indentures or bank credit agreements. Rules of this type are said to "ring fence" the utility and support the utility's credit quality. If sufficiently strict, these constraints may insulate the utility from the direct effect of the lower credit rating of its parent or affiliates.

Regulatory Environment

Regulation is a key factor in determining credit ratings for utilities. In evaluating the regulatory environment, Fitch considers the laws that dictate the terms and conditions of providing utility service as well as commonly employed policies and recent regulatory actions. The review of the regulatory environment is incorporated into the analysis of the business risk and financial condition of the utility. Fitch conducts the regulatory assessment on:

- A national basis, if utilities are regulated on a common basis nationally, with a single methodology that encompasses all utilities, as seen, for example, in the UK, Chile and Argentina.
- A statewide basis, if all utilities in a state are regulated similarly.
- A utility by utility basis, if the regulatory regime is unique to each utility.

Franchise or Concession Terms

Typically, regulated utilities serve customers pursuant to a franchise or concession, which may be exclusive or nonexclusive. In the case of a nonexclusive franchise, it is important to review the conditions under which a competing provider may offer service. For example, in Chile, the regulatory authority may grant permission to a second distribution utility to build facilities and extend service to new customers upon demonstrating that it is in the public interest and would be more efficient for the electric system as a whole. In practice, this usually affects only service expansion to remote communities near the boundaries of two utilities' franchise areas. Of greater credit concern is a situation where dual facilities compete.

A concession or franchise may be limited to a fixed term or exist in perpetuity, absent evidence of poor service quality. If there is a limit to the term of the franchise, it is important to consider that in the debt structure and credit evaluations.

In an increasing number of jurisdictions, retail franchises are being opened up to full or partial competition. The pace of deregulation and the company's competitive position will determine whether the process has a material impact on the cash flows of the business.

Price Setting

Fitch's review of a regulated utility includes consideration of the tariff-setting process established by law or regulatory order and the past record of regulatory actions, such as the following:

- Under cost-of-service regulation, tariffs are set by the regulatory body at a level to allow the utility to recover reasonable expenses and earn a fair return on invested capital.
- A variant on cost-of-service tariffs incorporates incentive mechanisms (sometimes called "performance-based rate-making"), permitting the utility to retain a portion or all of its' cost savings within a fixed band, while the balance of any cost savings is passed on to consumers in lower prices.
- Under price cap regulation, a maximum price is set for each individual utility. Utilities with the ability to keep expenses low or expand sales can enhance their profit and retain any additional revenues until the next price reset. However, if the price cap is set very low to capture all the expected future productivity improvements, some utilities may not even be able to earn a reasonable return on investment. Under the UK model (also common in Australia), the price cap is set for five years with a one-time price adjustment at the beginning of this period. The tariff automatically adjusts annually thereafter by an inflation index plus or minus a given factor ("x" factor). The initial price and the "x" factor are a function of the expected change in cost base of the utility (including assumed efficiencies) and the required return on and of capital over the period.

Whatever mechanisms are used for setting prices, the most important element in assessing regulatory climate within a particular jurisdiction is the extent to which regulators set prices at levels that allow utilities a reasonable opportunity to recover costs in a timely manner and earn a return on capital investment consistent with the level of risk. To the extent that a performance-based ratemaking or price cap program provides the utility an incentive for efficient operation, Fitch views that as a positive factor. Furthermore, credit quality is enhanced if the tariff for each type of customer reflects the true economic costs of providing service and one set of customers is not subsidizing others. When cross-subsidies exist among customer classes, customers with uneconomically high tariffs will have an economic incentive to reduce consumption, self-generate or seek alternate energy sources.

Among the tariff-setting practices that can affect the adequacy of price levels and are considered important by Fitch are the expected returns on capital relative to the industry average and the level of risk, the ability to pass through fuel and purchased power and other operating costs (see Commodity Price Exposure section on page 6), and the timing and adequacy of cash recovery of invested capital.

Tariff design, which can affect a utility's cash flow, is also considered. The tariff may be structured with a greater or smaller proportion variable to the volume of energy consumption or, in rare cases, as a flat fee insensitive to the amount of energy consumed. If a high proportion of the tariff is tied to energy consumption, the utility's cash flow may be highly sensitive to fluctuations in weather (for household and small business customers) and industrial activity (for manufacturers and extractive industries).

In mature markets, the volume of consumption and number of customers connected to the system will be relatively stable over time. However, in developing markets, moderate and consistent growth in per capita consumption and the customer base may lead to material volume growth. In such cases, a higher volume-related component in the tariff mitigates some of the risk of higher than expected demand leading to greater infrastructure investment requirements. Conversely, explosive growth in demand for service may produce soaring capital expenditure requirements that surpass the available cash flow. However, economic crises can shrink the volume of consumption, with a severe effect on a volume-sensitive tariff.

Potential for Regulatory Change

The final step in the regulatory assessment process is an evaluation of the potential for future statutory or regulatory changes. Sometimes public policy provides a safety net, protecting investors in utilities by providing compensation to utilities for investments determined uneconomical by any change in the rules. However, investors have at times been exposed to investment losses when the regulatory model changed without adequate compensation for investors who had invested in good faith based on the earlier framework.

In many developed nations, the outlook of individual utilities could change as a result of continuing adjustments in the industry structure. While there is a high degree of confidence that electric or gas consumers will remain connected to the distribution system of their local utility for the foreseeable future, competition has been introduced for some traditional distribution utility functions, such as retailing, metering, billing and energy services.

At some point, policy changes or future technology developments may lead to the migration of customers away from the wired distribution of electricity or distribution of natural gas over a public network, which could create a new round of stranded costs relating to utility assets. Whether regulatory price-setting would or could keep utilities economically whole in the face of a long, slow decline in sales due to competition from other fuels or self-generation is open to question.

Service Area Demographics

A regulated utility has a substantial, immovable fixed investment tied to a specific region and dedicated to serving a population of current and potential customers. Therefore, it is important to analyze the potential customer base and penetration of electric and gas service within it as well as population density and trends in the per capita usage of electricity and natural gas by consumers. Additionally, population trends, such as growth rates, migration and new housing starts, are indicators of the vitality of a consumer base. Also important are wealth indices, principally reflected as per capita and disposable income and employment and unemployment rates, since these factors affect consumers' ability to pay for utility service and the willingness of regulators to permit tariff increases. Trends in wealth indexes are predicted by studying such factors as new business formation, job creation and the health of the regional industrial economy.

Consumers of electricity and natural gas may include households, small-commercial businesses, very large office buildings, retail establishments, hospitals, small manufacturers, agriculture and irrigation, or large manufacturers and extractive industries. Each customer category exhibits a different demand profile (seasonality of demand, pattern of consumption during the day or week, sensitivity to business and industrial cycles, and sensitivity to weather). Consumption trends by category of customer over time are a part of the business review. This includes the analysis of the share of total unit volume sales per customer category, the share of sales' revenues relating to each customer category, and the average realized price or gross margin per customer in each category.

In some cases, a substantial portion of the utility's sales depends on a handful of extremely large customers. For example, in a region whose major industry is primary metal mining, milling and smelting operations, a downturn in commodity prices could result in the closure of a facility, affecting the utility's sale to the industrial operation as well as eliminating jobs and reducing the ability of household consumers and small businesses to afford electric, gas and water service. Therefore, utilities with a more diverse customer base (i.e., without large customer concentration in a single business or industry) tend to have more stable and predictable cash flows over time and typically enjoy higher credit ratings.

In some regions, consumers may have greater opportunities to install self-generation or switch to competing fuels, thus eliminating their consumption of electricity or natural gas distributed over the shared network. In addition, if another utility serves the region or a nearby region, the legal possibility and economic incentives for customers to seek service from the other utility (risk of bypass) must be considered. In the case of utilities with nonexclusive franchises, this analysis becomes even more important.

Energy Supply

In the case of electric and gas distribution systems, Fitch's credit analysis considers the availability of a reliable power or commodity supply.

For gas distributors, the availability of a continuing source of natural gas is a paramount concern. This involves a study of proven and probable reserves of natural gas in the relevant supply areas, exploration and drilling activity, and producers' success in finding new reserves to replace consumption, gas pipeline access and sources of gas imports. Supply can be disrupted when imports are reduced or blocked due to changes in national policies or international disputes, for example. For some electric distribution utilities, the diversity or stability of power supply and the access to and reliability of sufficient power transmission is of great importance.

Equally important is the degree to which the distributor is financially exposed to commodity supply costs. The analysis also considers the exposure to third-party energy suppliers that may default on their supply commitments under adverse circumstances. If a utility undertakes a voluntary competitive supply business, Fitch evaluates how the supply regime fits into the utility's overall strategic plan and whether the utility sufficiently managed upside opportunities and downside risks. If the utility is mandated to supply all consumption as a default provider or provider of last resort, the analysis focuses on determining whether the utility is reasonably assured of cost recovery and held harmless for actions, such as hedging activities, taken in good faith.

For integrated electric utilities that generate all or a substantial portion of the power needs of consumers, Fitch's credit analysis considers the fuel diversity and adequacy of the company's generating resources. The analytical focus is on the exposure to any particular fuel (see Commodity Price Exposure section), an extended outage of a large generating facility and the need for incremental generating capacity. Large new capacity requirements can drive future funding needs.

Commodity Price Exposure

Exposure to the cost of power or commodity supply may be mitigated by:

- Adjustment mechanisms that allow the utility to adjust its tariff periodically to match the cost of supplying power or natural gas.
- Ownership or control of generation capacity.
- Power or commodity supply contracts with reliable counterparties in volumes matching customers' expected demand (i.e., physical contracts).
- Options, futures or other derivatives (i.e., financial price risk management contracts), if available.

Ironically, even though each of these mitigating strategies reduces overall risk, additional risk may arise. For example, control and operation of power generation expose the utility to operating risk and ongoing capital spending requirements for future environmental compliance, while power and commodity supply contracts entail counterparty and settlement risk, and the utility may be exposed if the actual level of customer demand is lower or higher than the contracted supply.

In each case, Fitch analyzes the utility's supply responsibilities in conjunction with the hedging or risk-mitigation strategy. If a utility has a significant unhedged commodity price exposure or the hedging strategy introduces a meaningful level of risk, Fitch will increase the cash flow coverage ratios required and

reduce the amount of debt leverage that the utility can support relative to a utility without similar exposure.

Operating Efficiency

Cost and quality of service is a meaningful indicator of business effectiveness and credit quality. If the utility has below-average reliability, it may be subject to financial penalties or a reduced allowed return. Furthermore, major customers may be motivated by power outages or variations in voltage and the quality of network-distributed power to install on-site generation facilities and cease business with the local utility. In some jurisdictions, failure to meet specified service quality standards can result in penalties or, in the extreme, the loss of the franchise or concession, or the regulatory body may grant permission for an adjacent utility to offer service to that utility's customers.

When utilities are subject to price cap or incentive rate-setting, a utility that can increase efficiency and reduce unit costs will be able to earn or exceed the regulatory return. Low-cost operations can also be helpful for utilities subject to cost-of-service regulation by reducing the necessity for rate increases. An efficient operator with lower tariffs will also face less resistance to rate increases and be better able to mitigate technological and bypass risks (customers will have less economic incentive to install new types of equipment or bypass the utility) as well as customer loss (industrial customers will have less incentive to relocate to another region with lower rates).

To measure the efficiency of a power utility's production facilities, Fitch considers the capacity and availability factors of its power generating facilities. Capacity and availability factors that meet or exceed the industry average are indicative of efficient operations. Utility power producers that are unable to achieve the industry norm are likely to incur higher purchased power and operating costs that may not be recoverable from rate payers. Thermal efficiency/heat rate, production costs (fuel plus operating and maintenance expense) per unit of output and revenue per unit of output are also used as measures of operating efficiency.

The quality and efficiency measures used to evaluate a power or gas distribution operation include measures of the frequency and duration of outages and the time to restore service after outages. Losses in transmission and distribution are also an efficiency measure, although these are often influenced by geographical factors or the nature of the network over which the utility has no control. Factors such as population density, number and diversity of customers served, geographic location and regulatory policies in the jurisdiction may skew efficiency measures and must be considered when assessing the efficiency of distribution operations. For example, a utility serving a dispersed customer base in a rural farming region is likely to have a higher average total cost of distribution service than another utility serving a densely populated metropolitan area. The higher cost of service for the rural low-density utility will reflect the greater number of distribution facilities needed to serve fewer customers per mile and is not necessarily representative of inefficient operations.

Very effective utilities have efficient billing systems and high collection rates. However, for utilities in emerging markets, the ability to bill and collect revenues may be undermined by factors, such as unfavorable regulatory policies and customers' economic stress, as well as by internal factors, including inadequate information systems and weak management controls. For electric utilities, the difference between the amount of energy purchased or produced and the amount billed to consumers is generally studied and broken down into technical losses (relating to physical characteristics) and nontechnical losses (theft of service and inadequate billing controls.)

The condition of the utility's assets is also considered in the operations review. Fitch does not conduct engineering evaluations, but evaluations performed by independent engineering consultants may be a factor in initial rating reviews. Typically, the condition of fixed assets and information systems is revealed by the network's performance on a day-to-day basis and manifested in the operating efficiency, service quality and outage statistics.

Management and Strategy

The primary focus of a utility's management should be providing the appropriate level of customer service and service quality. Management must ensure that profit or cost-cutting motives are balanced with the need to deliver service at a level of quality that comfortably exceeds the requirements of the regulatory body or terms of the utility's franchise or concession. Management must also ensure that customers' service expectations are met. The utility business is characterized by a high reliance on favorable relations with regulatory entities and political authorities, which is the responsibility of senior management. If a utility's managers are not viewed by the regulatory body as credible and

trustworthy or are considered cavalier about the standards of service, there can be significant adverse consequences and financial effects.

If the utility is involved in the generation business, has energy supply responsibility or is a retailer, Fitch reviews the management information systems and control procedures used to measure and manage exposures to commodity price risk, counterparty risk and embedded options in commercial contracts. Senior managers and directors should have a full understanding of the business risks and receive frequent reports on potential exposures.

If the utility is involved in merger and consolidation activities or diversification into nonregulated business activities and these activities interfere with the primary mission or undermine the utility's financial well-being, the utility's ratings may be affected. Fitch assesses management's goals and business plan to determine whether the plan is well-suited to the utility's skills and resources. Also, the utility's strategic direction is analyzed as to its probable effect on the utility's risk profile and financial credit quality measures.

Financial Resources

After considering the qualitative and operating differences among utility companies, ratings are further distinguished by financial resources and performance. In evaluating the relative financial health of utility companies, Fitch focuses on the adequacy of cash flow to cover projected fixed costs and debt obligations under normal and stress circumstances. In Fitch's view, cash flow-based analysis provides the most accurate assessment of an issuer's ability to fund its business operations and meet debt service. Fitch ascribes greater importance to cash flow measures than to other more traditional earnings and capital structure indicators that play a secondary role in the rating analysis.

In assessing credit quality measures, historical and future trends are more important than a specific ratio at a given point in time. A review of historical financial measures is used to gauge the volatility or stability of the utility's cash flow and debt-service coverage ratios in past stress circumstances (e.g., extreme weather, tariff changes or economic recession). Then, Fitch reviews management's projections and constructs stress scenarios to test whether the entity's financial health would be materially impaired by a variety of adverse events, such as two or three years of unfavorable weather conditions, an adverse ruling in the next rate review or regulatory reset, lower industrial sales, higher operating costs or other risks specific to the utility's regulatory environment and business.

Capital Structure and Financial Flexibility

Fitch's evaluation of a utility's capital structure considers the type and amount of the utility's equity and debt in the context of the financial flexibility needed to balance the utility's operating cash flows, capital investment requirements, and possible and probable contingencies. Fitch also assesses debt type (secured or unsecured), maturity schedule and exposure to floating rate or foreign currency debt or refinancing risk. The debt maturity schedule should be sufficiently staggered so that the utility will not face the need to refinance substantial amounts of debt at a time when market conditions may be unfavorable or the utility's access to the bank market or capital market is constrained. If a significant amount of debt is denominated in a foreign currency, the utility should have a reasonable means of obtaining the foreign currency to pay interest and principal, and the analysis will incorporate stress cases testing the ability to cover obligations despite unfavorable exchange rates.

Financial Ratio Analysis

The financial analysis focuses on cash flow interest and fixed-charge coverage, leverage, liquidity and profitability. Fitch's financial analysis is cash flow-oriented but also incorporates traditional accrual accounting measures. Ratio calculations typically exclude items that Fitch deems as nonrecurring, such as asset impairments, restructuring charges, and gains and losses on asset sales. Adjustments are also made for securitization and operating lease transactions.

The cash flow analysis relies on funds flow from operations (FFO) and, to a lesser extent, earnings before interest, taxes, depreciation and amortization (EBITDA) as the primary indicators of a company's ability to generate funds from ongoing operations to service debt and fixed charges. Each measure is compared to interest, fixed charges and total debt to assess a company's leverage and interest protection.

FFO (as adjusted by Fitch) is derived from the consolidated statement of cash flow and is considered a more precise measure of the cash available to service debt, but the data needed may not be available in all jurisdictions. EBITDA is derived from figures on the income statement and is a rough but useful approximation of cash flow. Fitch adjusts

EBITDA and FFO by adding back rental expense or similar payments to form EBITDAR or FFO plus rents.

Fitch relies on several coverage ratios to assess a company's ability to meet its interest and fixed charge obligations: FFO interest coverage, FFO fixed-charge coverage, EBITDA interest coverage, EBITDAR fixed-charge coverage, and for utilities regulated on a UK-style basis post-maintenance interest charge coverage, which is FFO coverage, including a deduction for capital maintenance in the numerator (For additional details on post-maintenance interest coverage, please refer to Fitch's report "Post-Maintenance Interest Coverage Ratios for UK Utilities" dated Feb. 28, 2007.) Fixed charge coverage ratios include rental expense (both interest and principal amortization) in the numerator and denominator (For additional information, please refer to Fitch reports "Operating Leases: Updated Implications for Lessees Credit" dated Dec. 20, 2006 and "Cash Flow Measures in Corporate Analysis" dated Oct. 12, 2005). Interest expense is calculated before any credit (reduction) for capitalized interest and/or allowance for borrowed funds used during construction. EBITDA excludes nonrecurring nonoperating income.

Fitch's primary leverage measures are the ratios of FFO-to-debt (or debt-to-FFO), debt-to-EBITDA, debt-to-EBITDAR and for UK-style regulatory regimes debt-to-regulatory asset value (RAV). In each case, debt is adjusted to reflect debt equivalents and/or off-balance-sheet debt. Traditional balance-sheet measures of gross debt-to-capitalization and net debt-to-equity (gearing ratio) are also considered but given less weighting. These measures rely on the book value of equity, which is subject to variations in applications of accounting standards and may be less meaningful indicators of financial leverage.

Profitability is also an important financial measure. To attract capital and remain financially viable, utilities must operate profitably over the long term. Profitability is measured by return on average common equity, operating margin and return on assets.

Financial flexibility is more qualitative and is based on Fitch's assessment of capital market access, availability of bank facilities and a review of marketable assets. Fitch also assesses debt type (secured or unsecured), maturity schedule and exposure to floating-rate debt or refinancing risk.

Liquidity

Fitch expects a utility company to have sufficient liquidity to meet its normal business activities as well as cover adverse stress events. The liquidity analysis begins with a base case forecast of the company's expected FFO less its working capital needs, capital expenditures and dividends. The residual free cash flow or cash flow deficiency is matched against debt maturities to assess the sufficiency of internal cash sources to meet ongoing operating and financial obligations. The base case also considers the likely cash needs arising from contingent liabilities, such as guarantees and obligations of nonconsolidated affiliates important to the company's core business lines.

Fitch generally assumes that all cash on hand and available borrowing capacity under credit facilities may be used to cover cash deficits, subject to adjustments based on Fitch's evaluation of the company's ability to renew expiring credit facilities or meet conditions precedent to borrowing. Secondary funding sources, including asset sales, equity and debt issuance, and parent capital contributions as well as planned cash uses, such as equity repurchases or additional debt repayment, are also considered.

After evaluating the company's base case liquidity strength, Fitch considers additional stress case conditions that could further strain a utility's cash position, given its individual circumstances. The two broad categories of stress events are operational events and events relating to trading and marketing activities. The selected stress events have a reasonable probability, but not expectation, of occurring and the actual occurrence would result in a significant drain on cash liquidity.

Operational stresses include but are not limited to a prolonged unplanned outage at key operating facilities, severe price movements for an unhedged fuel need and the failure of a fuel or power supplier to make delivery or repair costs from a hurricane or serious storm. Adverse results in a pending investigation or lawsuit are also considered as a potential operational stress.

For companies that trade energy commodities Fitch considers the collateral requirements related to adverse market price movements and changes in credit ratings (for additional details on stress cases, please refer to Fitch's report, "Evaluating Liquidity in the Power and Gas Sector" dated Sept. 1, 2005).

Available liquidity for the stress analysis is limited to unrestricted cash and funds available under committed bank credit facilities. The expected loss related to the adverse stress scenario should be covered by the availability at least 1.0 times. In determining the adequacy of a utility's cash flow under stress conditions, Fitch recognizes that the company has the flexibility to lower its dividend payments, projected share buybacks and discretionary capital expenditures. Fitch assumes that in a stress scenario a company will draw on its bank lines to fund the liquidity needs, and will add the draw to the company's debt and reduce EBITDA for any anticipated earnings effect of the events.

Risk Assessment and Guideline Credit Ratios

Fitch analysts use benchmark credit ratios and comparisons with peer companies to compare utilities and related companies in the utilities sector. The benchmarks may differ in various jurisdictions and between different types of utilities. The benchmarks presume that companies with progressively higher variability of operating cash flow (higher business risk) have progressively lower debt capacity.

A quantitative approach is limited in some jurisdictions by the lack of sufficient data. For a company with no prior operating history, the experience of peer companies may provide a useful proxy, but in some markets undergoing restructuring, reliable peers may not be available. It should be noted that the same benchmarks cannot be applied directly to utilities in different nations or under different ownership situations. Currency and economic volatility and political risks vary from one nation to another and require adjustments in the standards, as do differences in tax circumstances, transparency of the regulatory regime, ownership structures (e.g., municipal, cooperative or state ownership) or implicit governmental support.

■ Financial Adjustments

Debt Equivalents

Fitch calculates a debt equivalent for certain off-balance-sheet and other debt-like obligations. The debt equivalent is calculated using the present value of the remaining rental obligation or a multiple of lease rental payments (commonly 8 times). For material lease obligations, the present value approach is the preferred methodology. Power plant tolling agreements are also capitalized using the present value approach. If the lessor is a special-purpose entity (SPE), the entire SPE is consolidated into the lessee. In each instance, an interest component is calculated and added to interest expense for the calculation of adjusted financial ratios. When using the present value approach, the discount rate is multiplied times the implied lease principal. When using a multiple of lease rental payments the entire rental payment is treated as interest expense. For more information, see Fitch's Criteria report, "Operating Leases: Updated Implications for Lessees' Credit," dated Dec. 20, 2006.

Nonrecourse Debt Obligations

Nonrecourse debt obligations are evaluated in terms of strategic relevance of the asset or business unit and the level of financial separation. If deemed noncore by Fitch, the debt can be deconsolidated. When a unit is determined to be of credit and debt is deconsolidated, all income and dividends are also excluded from financial projections.

Corporate Guarantees

Guaranteed debt of nonconsolidated entities is consolidated. With respect to performance guarantees, Fitch's analysts forecast whether there is any expected liability and if so, may consolidate the expected amount.

Hybrid Securities

Fitch gives equity credit to certain hybrid securities that are neither common stock nor ordinary debt. The equity credit consists of five classes: 100%, 75%, 50%, 25% and 0%. The proportion of equity credit is influenced by the convertibility or junior ranking, the interest/dividend deferral mechanism, the effective maturity and the absence of investor protections, such as covenants and cross defaults. In adjusting financial leverage and capital ratios Fitch uses the adjusted equity and debt derived from appropriate equity credit attributed to each hybrid security. Interest coverage is calculated in two alternate ways: with all interest or dividends included in the calculation of interest and fixed charges and with all deferrable dividends or interest eliminated. Fitch expects that 70% or more of the entity's equity capital will be in the form of common equity securities, since hybrid securities are most equity-like when the issuer is in distress but offer less support when the entity's financial condition is merely weakening. For additional information on Fitch's treatment of hybrid securities, please refer to the special report, "Equity

Credit for Hybrids and Other Capital Securities," dated Sept. 27 2006.

Copyright © 2007 by Fitch, Inc., Fitch Ratings Ltd. and its subsidiaries. One State Street Plaza. NY, NY 10004.
Telephone: 1-800-753-4824, (212) 908-0500. Fax: (212) 480-4435. Reproduction or retransmission in whole or in part is prohibited except by permission. All rights reserved. All of the information contained herein is based on information obtained from issuers, other obligors, underwriters, and other sources which Fitch believes to be reliable. Fitch does not audit or verify the truth or accuracy of any such information. As a result, the information in this report is provided "as is" without any representation or warranty of any kind. A Fitch rating is an opinion as to the creditworthiness of a security. The rating does not address the risk of loss due to risks other than credit risk, unless such risk is specifically mentioned. Fitch is not engaged in the offer or sale of any security. A report providing a Fitch rating is neither a prospectus nor a substitute for the information assembled, verified and presented to investors by the issuer and its agents in connection with the sale of the securities. Ratings may be changed, suspended, or withdrawn at anytime for any reason in the sole discretion of Fitch. Fitch does not provide investment advice of any sort. Ratings are not a recommendation to buy, sell, or hold any security. Ratings do not comment on the adequacy of market price, the suitability of any security for a particular investor, or the tax-exempt nature or taxability of payments made in respect to any security. Fitch receives fees from issuers, insurers, guarantors, other obligors, and underwriters for rating securities. Such fees generally vary from US$1,000 to US$750,000 (or the applicable currency equivalent) per issue. In certain cases, Fitch will rate all or a number of issues issued by a particular issuer, or insured or guaranteed by a particular insurer or guarantor, for a single annual fee. Such fees are expected to vary from US$10,000 to US$1,500,000 (or the applicable currency equivalent). The assignment, publication, or dissemination of a rating by Fitch shall not constitute a consent by Fitch to use its name as an expert in connection with any registration statement filed under the United States securities laws, the Financial Services and Markets Act of 2000 of Great Britain, or the securities laws of any particular jurisdiction. Due to the relative efficiency of electronic publishing and distribution, Fitch research may be available to electronic subscribers up to three days earlier than to print subscribers.

The McGraw-Hill Companies
STANDARD & POOR'S RatingsDirect®

RESEARCH

U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

Publication date: 30-Nov-2007
Primary Credit Analysts: Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com
William Ferara, New York (1 212-438-1776; bill_ferara@standardandpoors.com
John W Whitlock, New York (1) 212-438-7678; john_whitlock@standardandpoors.com
Secondary Credit Analyst: Michael Messer, New York (1) 212- 438-1618; michael_messer@standardandpoors.com

The electric, gas, and water utility ratings ranking lists published today by Standard & Poor's U.S. Utilities & Infrastructure Ratings practice are categorized under the business risk/financial risk matrix used by the Corporate Ratings group. This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors. Incorporating utility ratings into a shared framework to communicate the fundamental credit analysis of a company furthers the goals of transparency and comparability in the ratings process. Table 1 shows the matrix.

Table 1

Business Risk/Financial Risk

	Financial Risk Profile				
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The utilities rating methodology remains unchanged, and the use of the corporate risk matrix has not resulted in any changes to ratings or outlooks. The same five factors that we analyzed to produce a business risk score in the familiar 10-point scale are used in determining whether a utility possesses an "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" business risk profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

As the matrix concisely illustrates, the business risk profile loosely determines the level of financial risk appropriate for any given rating. Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP.

Financial risk is assessed for utilities using, in part, the indicative ratio ranges in table 2.

Table 2

Financial Risk Indicative Ratios - U.S. Utilities

(Fully adjusted, historically demonstrated, and expected to consistently continue)

	Cash flow		Debt leverage
	(FFO/debt) (%)	(FFO/interest) (x)	(Total debt/capital) (%)
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50

The indicative ranges for utilities differ somewhat from the guidelines used for their unregulated counterparts because of several factors that distinguish the financial policy and profile of regulated entities. Utilities tend to finance with long-maturity capital and fixed rates. Financial performance is typically more uniform over time, avoiding the volatility of unregulated industrial entities. Also, utilities fare comparatively well in many of the less-quantitative aspects of financial risk. Financial flexibility is generally quite robust, given good access to capital, ample short-term liquidity, and the like. Utilities that exhibit such favorable credit characteristics will often see ratings based on the more accommodative end of the indicative ratio ranges, especially when the company's business risk profile is solidly within its category. Conversely, a utility that follows an atypical financial policy or manages its balance sheet less conservatively, or falls along the lower end of its business risk designation, would have to demonstrate an ability to achieve financial metrics along the more stringent end of the ratio ranges to reach a given rating.

Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide--it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix. Most outcomes will fall within one notch on either side of the indicated rating. Larger exceptions for utilities would typically involve the influence of related unregulated entities or extraordinary disruptions in the regulatory environment.

We will use the matrix, the ranking list, and individual company reports to communicate the relative position of a company within its business risk peer group and the other factors that produce the ratings.

Analytic services provided by Standard & Poor's Ratings Services (Ratings Services) are the result of separate activities designed to preserve the independence and objectivity of ratings opinions. The credit ratings and observations contained herein are solely statements of opinion and not statements of fact or recommendations to purchase, hold, or sell any securities or make any other investment decisions. Accordingly, any user of the information contained herein should not rely on any credit rating or other opinion contained herein in making any investment decision. Ratings are based on information received by Ratings Services. Other divisions of Standard & Poor's may have information that is not available to Ratings Services. Standard & Poor's has established policies and procedures to maintain the confidentiality of non-public information received during the ratings process.

Ratings Services receives compensation for its ratings. Such compensation is normally paid either by the issuers of such securities or third parties participating in marketing the securities. While Standard & Poor's reserves the right to disseminate the rating, it receives no payment for doing so, except for subscriptions to its publications. Additional information about our ratings fees is available at www.standardandpoors.com/usratingsfees.

Privacy Notice

Copyright © 2008 Standard & Poor's, a division of The McGraw-Hill Companies. All Rights Reserved.

APS
A subsidiary of Pinnacle West Capital Corporation

Jack Davis
President and Chief Executive Officer

Tel 602/250-3529
Fax 602/250-3002

Mail Station 9080
P.O. Box 53999
Phoenix, AZ 85072-3999

January 23, 2006

Commissioner Kristin K. Mayes
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007-2996

RE: APS' Cost-Containment Measures

Dear Commissioner Mayes:

This letter is in response to your January 11, 2006 letter regarding the cost management efforts at Arizona Public Service Company ("APS"). Before turning to those issues, however, I want to stress that the financial crisis facing the company and its customers is primarily the result of the mounting fuel and purchased power costs that APS has been unable to recover on a timely basis under the Commission approved PSA, and not because of some shortcoming in APS' cost management processes. Our difficulties are further compounded by a "price squeeze" (similar to that recently faced by California and other utilities) that has customers paying rates based on 2002-2003 expenses while APS must pay the much higher 2006 costs to provide service.

That being said, your letter asks about APS' commitment to contain its costs and expenses. To be clear, managing costs is an integral part of APS' philosophy. In light of record customer and energy growth, our challenge has and will continue to be managing costs that do not compromise our ability to reliably serve our customers at reasonable costs both today and in the future.

With that introduction, let me address your inquiries.

APS Hedging Policies and the Annual Fuel and Purchased Power Cap

In your letter, you refer to: "our apparent failure to keep APS' natural gas purchases under the $776.2 million cap on annual power supply costs." This statement reflects a fundamental misunderstanding of the goals of a responsible hedging policy and would implicitly suggest some imprudent fuel and purchased power steps by APS.

A hedge is a technique designed to reduce or eliminate price risk—it is not designed to lock in a predetermined future cost figure irrespective of (i) high premium costs, (ii) the loss of market flexibility, or (iii) the increase in volumetric risk associated with higher levels of hedging. Since the prices of natural gas and purchased power are

extremely volatile, and energy requirements fluctuate on both short term and long term periods, a sound hedging philosophy allows APS to eliminate much (but not all) of the price risk for customers associated with the often dramatic short and mid-term price fluctuations in these markets without incurring the counter-vailing diseconomies described above.

APS has hedged natural gas and purchased power requirements for native load customers for a number of years, with price stability properly being the primary underlying goal of our system hedge philosophy. Through our system hedge approach, financial risks associated with projected fuel and purchased power requirements are systematically hedged at various levels during the three years prior to delivery. Our hedging practices involve setting definitive target hedge levels, strict compliance in meeting those hedge levels, and utilizing sophisticated buy/sell strategies, all undertaken with senior management oversight and direction. APS' system hedging philosophy does not try to guess the direction of the commodity markets—that is what speculators do, and we do not believe it is appropriate to speculate on behalf of our customers.

By hedging 85% of our purchased power and natural gas needs using pre-established intervals and hedge percentage levels over a three-year horizon, APS can mitigate the impact of volatile natural gas and purchase power prices and still allow for changes in load and other short term market variables. Some of the specifics of our hedging policy and practices were outlined in detail during the Commission's September 2005 natural gas workshop. Because price stability, and not speculative gain, is the goal of hedging, the economic impact of hedging can and will vary with the swings in commodity prices in short term markets. For example, if a hedge is purchased and valued at a cost below the current market value, the value of the hedge itself is positive, and can result in lower costs to the customer versus relying on spot market prices for procurement. This was the case for APS in 2005, when the value of hedging saved APS ratepayers approximately $120 million in fuel and purchased power costs. Put another way, if APS had not hedged and instead relied solely on the short term markets to purchase its projected gas and purchased power volumes, the eventual costs of those commodities would have been $120 million higher. Similarly, while the market value of hedges changes daily with the corresponding changes in market prices the value of APS' forward year hedges measured as of January 10, 2006 for the years 2006 and 2007 are as follows:

— Calendar 2006: $128 million

— Calendar 2007: $110 million

It is important to note that, notwithstanding the above financially positive positions stemming from our hedging program, the value of these hedges could be reduced or eliminated if the short term price of gas and purchased power were to drop lower than the hedged price. In those instances, even though the primary goal of price stability is realized, the final costs of hedging would be higher than if we had relied (but only with the benefit of hindsight) exclusively on short term market prices. Such a result

would not mean that the hedges were imprudent. Described another way, hedging is essentially price insurance. Insurance does not lose its value nor is its purchase imprudent simply because the risk insured against does not materialize.

A sound hedging philosophy is a critical element to our business. The failure to follow an established hedge plan, and instead wait for the spot market can be catastrophic, as commodities market trading has proven time and time again. Just as risky is a hedging program that tries to predict the market or one that fixates on a specific cost figure. Our hedging program is a sound risk management tool and provides a long-term safety net for APS customers.

Other fuel-related cost containment efforts

Aside from hedging, APS has taken other steps to contain fuel and purchased power costs. The following are just a few examples of such steps:

- ✓ Power Plant Efficiency/Unit Uprates Projects — Annualized fuel savings from increasing the efficiency/uprating the capacity at several APS units (Palo Verde, Cholla, and Redhawk) will save ratepayers an estimated $38 million in 2006 based on December 31, 2005 forward market prices.

- ✓ Nuclear Fuel Procurement — By consolidating purchases APS has achieved approximately $23 million in savings over the last two years.

- ✓ Coal and Coal Transportation Agreements — Through active management of its coal and coal transportation agreements, APS' average coal expense increases have been limited to 23% since 2000, in comparison to the Powder River Basin market, where prices have increased by over 100% during the same period. Part of these savings resulted from multi-year negotiations to improve rail economics and service with Burlington Northern Santa Fe in support of our Cholla generating station and contractually fixing the term of the contract for lower cost incremental pricing for our Four Corners generating station. Moreover, APS anticipates its recently executed 19 year, 65 million ton coal supply agreement with Peabody Energy will lend itself to improved economics for the Cholla generating station relative to future coal purchases in light of today's current market conditions.

- ✓ Natural Gas Transportation Agreements — Active management of the El Paso Natural Gas Transportation agreements have produced annual savings of more than $4 million per year.

Capital Infusions and Dividends

A review of APS' revenue deficiency for the years 2001 through 2005 shows that APS failed to earn its allowed return on equity by over $220 million. This equates to a pre-tax revenue shortfall from customers (and a loss to shareholders) for the same period

of over $370 million. In addition, the company's shareholders have absorbed almost $19 million of presumptively prudent 2005 fuel expenses through the 90/10 sharing feature of the PSA. As fuel and purchase power costs increase, so too will this loss to shareholders. By the end of 2006, we estimate the portion of otherwise recoverable fuel costs borne by shareholders will have grown to more than $45 million.

Your letter suggests additional equity infusions from Pinnacle West to APS. In the last twelve months, Pinnacle West has infused $460 million of equity into APS. Without this infusion of equity by Pinnacle West, APS would already be "junk" rated. It also makes APS' capitalization structure 54.5% equity.

The problem with our financial health is weak funds (i.e. revenues) from operations in comparison to our projected construction expenditures and our total debt, and not from any the lack of additional equity investment. Because of the significant mis-match between the price of fuel charged customer, and the costs incurred by APS, cash flow from customers is simply not sufficient to cover purchased power and fuel costs, operating expenses and construction expenditures. APS can survive short periods of time with weak cash flow, but eventually its financial health is compromised if such cash flow condition persists. This is why we find ourselves on the edge of a "junk" bond rating. As a result of such a rating, as detailed in our filed testimony, estimates are that the amount of additional annual interest expense would grow to $115 million to $230 million by 2015; a cost that can easily be avoided by aligning fuel and purchased power costs paid by the customer with those paid by APS.

On the issue of dividends, APS' dividend has remained unchanged since 1991. Cutting APS dividends would further and dramatically affect the equity market's negative perception of APS and Pinnacle West. In fact, I doubt that Pinnacle West would have been able to raise the $250 million of new equity in April of last year which was infused into APS, had it or APS been cutting dividends. Because APS is the second fastest growing electric utility in the nation, it is vital that we remain an attractive investment in all financial markets. It is difficult to imagine that any prudent investor would invest their money into a company with significant and growing unrecovered costs, sub par returns and the cutting of dividends. Finally, for the same reasons discussed with reference to additional equity infusions from Pinnacle West, a reduction in the APS dividend would not resolve an operating cash deficiency caused by the Commission's failure to permit timely fuel cost recovery or provide the financial community any greater assurance as to the recovery of fuel and purchased power costs, which is the source of its concerns.

Non-fuel cost management

In your letter, you reference executive bonuses, travel and advertising. Together, these account for only 0.2% of our costs. Moreover, they represent an even smaller amount of the revenue increase we are asking for in our permanent rate case. Nevertheless, I will attempt to address these items as well as the other non-fuel cost containment efforts being made by APS.

Let me first discuss advertising and APS' involvement in local sporting events. APS has been and continues to be an active participant in supporting our state and the communities we serve – but we are not asking that the funds that underlie this involvement come from customers. The communications costs included in our permanent rate filing are related to conservation/energy efficiency and customer service messages. APS customers do *not* absorb charity costs or the other cash and non-cash contributions we make for the benefit of Arizona communities. Moreover, the volunteer hours by our employees across the many worthwhile projects have been among the highest of any Arizona based company but likewise do not cost APS customers anything, yet clearly bring value to the community.

The issues of executive incentives and travel are not germane to the recent emergency filing, which is focused solely on the fact that APS has still not been reimbursed hundreds of millions of dollars in purchased fuel and power costs to meet its ratepayers' power requirements. For your information, the test year required by Commission Staff for our pending permanent rate case contains officer salaries at 2004 levels and no executive incentive payments and minimal travel expenditures. While the review and determination of the recovery of those costs, however de minimis, is appropriate in the pending rate case, we believe it is not material in evaluating the current emergency filing.

Let me now turn to the more generic question of cost management in the non-fuel area. APS has a long record of actively pursuing disciplined cost management as a tenet of our business. APS has successfully managed costs and staffing levels over the last several years, while meeting customer growth averaging around 4% per year. Between 2001 and 2005, operating costs as a ratio of energy sales (measured in cents / kwh) have remained in the 2.0 to 2.2 cents/kwh range. During that same time, the customer per employee ratio has grown from 196 customers per employee in 2001 to 220 customers per employee in 2005, an improvement of 12%. Our construction cost of each residential meter set from 2001 through 2005 has increased less than 3% per year, well below the inflation rate of raw materials and labor for this task. These bottom line results are even more impressive considering that APS serves a larger and more sparsely populated territory than other utilities in Arizona.

Virtually every APS department has worked to reduce or contain its costs and expenses. The following are samples of steps which have and will result in savings to APS ratepayers.

- ✓ Taxable Debt Interest Savings — APS' treasury department implemented an aggressive strategy of renegotiating debt service requirements which result in an annual interest savings of more than $22 million compared to 2000.

- ✓ Tax Exempt Portfolio Savings — During the period of 2001 through 2005, the APS treasury department realigned APS' tax exempt debt in order to achieve interest savings and to diversify credit support. As a result of this realignment, annual savings are more than $3 million.

- ✓ APS has implemented over the last several years aps.com to handle certain customer inquiries and transactions resulting in estimated savings of approximately $3 million annually.

The above are but a small sample of actions we take every day to undertake every reasonable measure to look out for our customers. In the last decade, while power prices have rocketed skyward and rolling brownouts caused by lack of generation capacity have been occurring in other states, we have stayed steadfast in our commitment to providing Arizona customers reliable energy and the reason we were able to reduce our prices 16% prior to April of last year was because of these efforts. We are proud of our record of reliability and proud of our efforts to contain costs for APS customers.

Conclusion

Our financial health is vitally important to customers, shareholders, employees and to all Arizonans, whose economic prospects are surely dependent on a strong APS capable of supporting the continuing growth of our state.

The company's base rate case will provide sufficient opportunities for all parties to review the company's overall costs in depth. The interim filing (which is subject to refund based on the final rate case decision) is about unrecovered fuel costs which have placed the company in a precarious financial position that needs to be remedied immediately.

Very truly yours,

Jack E. Davis
President & CEO
Arizona Public Service Company

cc: Chairman Jeff Hatch-Miller
Commissioner William A. Mundell
Commissioner Marc Spitzer
Commissioner Mike Gleason
Ernest Johnson
Brian McNeil
Heather Murphy
Docket

ATTACHMENT DEB-6

ARIZONA PUBLIC SERVICE COMPANY

FEDERAL AND STATE
PUBLIC AFFAIRS

LOBBYING ACTIVITY HIGHLIGHTS
2007

INTRODUCTION

At Arizona Public Service Company ("APS" or "Company"), our strategies are driven by one overriding concern – sustaining Arizona while meeting the challenge of continuing customer growth. We engage this challenge by meeting today's energy demand as reliably and affordably as possible while working every day to create an even better energy future for Arizona.

One effective and cost-efficient method of attempting to ensure that APS continues to provide electricity at reasonable prices is the political lobbying process. APS has both a right and a legitimate business need to engage in discussions with and educate political decision-makers on those issues that are important to the Company and its customers. Lobbying activities such as these are vital to the country's political system, presenting an effective means of educating our federal, state and local officials on how the issues before them affect the various, unique areas in which they legislate. This is particularly important for a rapidly growing state like Arizona, where a thriving modern economy depends on the ability of utility companies to provide reliable and sustainable solutions to the energy needs of businesses and individuals. Lobbying activities are essential in shaping the legislative mandates that affect the core of the Company's business, and these activities in turn also protect the interests of our customers. Informing public officials and helping shape public policy is a crucial part of what we do.

APS maintains a presence in Washington, D.C., urging lawmakers to strengthen the utility industry by retaining policies to, for example, provide more research funding to lower the future cost of renewable resources and develop new approaches to financing the first group of new nuclear units. Policies such as these will lower the cost to APS of providing electricity to Arizona – a benefit that will ultimately inure to APS's customers. APS also maintains a strong presence before state government to urge, among other things, fair and competitive taxation for Arizona businesses and protect the interests of APS's customers and investors. The impact of possible additional future property taxes also requires the Company to maintain a voice in the state's political process, given the urgency of APS's need over the next ten years to invest about $15 billion in Arizona's electric infrastructure. Lobbying activities such as these continue to provide significant cost-savings to both the Company and its customers, not only in the short term, but in the long run.

2007 HIGHLIGHTS

In 2007, the Company's lobbying activities included those focused generally on the following subject matters:

- Taxes/Business Issues: Among other incidental tax and/or business issues that affect all businesses, the Company monitors and supports efforts towards extending the renewable tax credit to enhance the installation of cost-effective solar, wind, and biomass generating facilities. The Company also supports accelerated tax depreciation for the construction of distribution and transmission facilities, which is important to a fast-growing state like Arizona. APS opposes new energy taxes that would be disadvantageous to its customers.

- Global Climate: Pinnacle West, on behalf of APS, generally supports a cap and trade/auction legislative approach to combat global warming. The Company is watching closely how the various legislative proposals on this issue develop, and focuses particularly on how these proposals would allocate allowances or credits for high growth regions of the country. The Company is also concerned about the costs its customers would have to absorb if one of the more extreme and ill-conceived proposals were to become law.

- Nuclear: Pinnacle West supports nuclear energy as a potential means of combating global climate change. The Company also closely monitors any legislation that would adversely impact the safe, secure, and efficient operations of existing nuclear plants as well as the Yucca Mountain Project.

- Environmental, Land, and Water: Pinnacle West is monitoring the progress of a federally mandated Renewable Portfolio Standard ("RPS") for utilities. The Company's position on this legislation is, first and foremost, that any federal RPS should not preempt or undermine a state RPS or RES. Second, if a federal RPS exists, it should apply broadly. Finally, nuclear generation should be included in the RPS resource mix. At the state level, the Company supported two important renewable initiatives involving the installation of solar devices in businesses through transfer of solar credits and state contracting practices for energy efficient heating and cooling equipment.

The following discussion identifies specific of areas of focus and successes at the both federal and state levels.

FEDERAL AFFAIRS

Energy issues at the federal level have a considerable potential impact on APS and its customers, and it is important that policy-makers in Washington appreciate the impact of any prospective legislation on Arizona. This is especially true given Arizona's unique position as one of the fastest growing states in the nation, in which certain energy laws (such as potential cap and trade legislation relating to greenhouse gas emissions) could, if passed, have a disproportionately negative impact on Arizona electric consumers. Every other state in the nation has utilities and special interest groups with specific issues and concerns — some of which are contradictory to those of Arizona and APS. It is important that APS maintain a voice in this ever-changing political environment to ensure that the interests of the Company and its customers are not overlooked, and that the political playing field is not left open to the lobbying efforts of other utilities, states, and regions that would advance their interests at Arizona's expense.

Successes at the federal level include:

Equipment import tariff suspension. In the past, the Company led the nuclear industry's efforts to suspend the tariff on the importation of replacement steam generators and nuclear vessel heads for Palo Verde. This provision was added to the Trade Bill of 2002 over significant opposition and has saved approximately $10 million in costs at Palo Verde. In an effort to retain those savings today, the Company is again leading the industry effort to combat a movement to repeal this crucial piece of legislation.

Solar Income Tax Credit renewal. The Federal Affairs Department is currently working with a coalition of utilities to maintain the Solar Investment Tax Credit (currently scheduled to expire in December of 2008), which was removed from the most recent federal energy bill that was signed into law by President Bush in December 2007, so that APS and its customers can continue to take advantage of the benefits offered by the tax credit. This legislation is a lynchpin of the recently announced, utility-scale solar power plant planned by APS and Abengoa Solar, which would bring $1 billion of solar investment to Arizona.

Nuclear fuel import benefit. The Company's federal lobbyist is working with a coalition of nuclear power plant owners and operators to oppose a bill that would place a tariff on the shipment of enriched nuclear fuel into the United States. Currently, this fuel source is selling at below-market prices. By opposing this bill, APS's Federal Affairs Department seeks to preserve a direct cost benefit to APS customers in the form of lower nuclear fuel costs. If a tariff is imposed, this benefit would most likely disappear.

Climate change legislation. The Federal Affairs Department is also playing an active role in shaping the emerging climate change policy, which is the topic of numerous federal bills. While any one of these bills, if passed, will ultimately increase costs to the Company and its customers, the financial impact of each to APS and its customers varies significantly, and the ultimate result could increase costs by as much as tens of millions of dollars in the short-term and hundred of millions in the long-term. For example, the Lieberman-Warner bill would cost APS roughly $131 million in 2012, $334 million by 2020, and rise to more than $1 billion per year by 2030. This bill would be substantially more costly than others, such as the Bingaman bill, which would increase APS's costs by $77 million in 2012 and would ramp up to more than $200 million in 2020 (a relatively smaller financial impact). APS's lobbying efforts with respect to this emerging body of legislation are aimed at educating legislators on the financial impact of the proposals and identifying other regional concerns, particularly in states like Arizona and New Mexico that are experiencing high population growth.

STATE AFFAIRS

State energy policy. The Company's Public Affairs Department is currently working with the Governor's Office, Legislature, and interested stakeholders to devise state-wide energy legislation that makes sense to Arizona customers and utilities alike, and which also acknowledges the Commission's authority. While the fiscal, public policy, and other important impacts of such legislation are not yet calculable, the benefits to APS's customers of the Company's involvement at this early stage and throughout the development of the bill will undoubtedly exceed the costs involved.

Property tax legislation. Because APS has invested in a considerable amount of property in Arizona, the Company's Public Affairs Department consistently advocates tax policy that would lower APS's property tax bill

(a savings that is ultimately passed on to customers). As part of that effort, APS's state lobbyists worked to support two successful pieces of legislation that will save APS and its customers millions of dollars per year in property taxes.

- HB2784 (Laws 2007, Chapter 258), for example, accelerated the reduction in the property assessment ratio (the ratio that determines the value of assets for property tax purposes), resulting in a total savings for APS and its customers of about $20 million per year when fully implemented.
- HB2657 (Laws 2007, Chapter 203), another important property tax bill, clarified problems that had arisen over the valuation of land associated with generation facilities, resulting in a tax savings to APS and its customers of roughly $700,000 annually (not to mention the reduction of costly and time-consuming appeals of higher tax bills).

Metal theft. Given the increasing prices for commodities in general (and copper in particular), legislation pertaining to metal theft ranked high among the Company's operational concerns, and our Public Affairs delegation worked towards the successful passage of HB2314, which imposed stringent record keeping requirements on scrap metal dealers and increased the penalties for damages to utility property caused by stealing metal.

APS firmly believes that the positions and efforts it undertakes in the political arena produce benefits to its customers. Nevertheless, the nature of the political process – consisting of long, drawn-out negotiations lasting for several sessions over bills with fluid iterations that change from one session to the next – makes it remarkably difficult to track the extent to which the Company's lobbying efforts actually caused an end result, particularly if looking at one historical test year in isolation. Even so, by educating federal and state political officials about the unique issues these bills present to APS and its customers, and finding allies in other organizations that will join with the Company in support of or opposition to a bill, the Company makes it more likely that the end result will be one that protects the interests of its customers and its shareholders alike.

William E. Avera

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF

WILLIAM E. AVERA

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

DIRECT TESTIMONY OF WILLIAM E. AVERA

Table of Contents

I. Introduction and Summary of Conclusions 1
- A. Summary of Conclusions 1
- B. Qualifications 6
- C. Overview 8

II. Fundamental Analyses 10
- A. Arizona Public Service Company 10
- B. Utility Industry 13

III. Capital Market Estimates 21
- A. Economic Standards 21
- B. Discounted Cash Flow Analyses 25
- C. Capital Asset Pricing Model 44
- D. Proxy Group Cost of Equity Estimates 47

IV. Return on Equity for APS 47
- A. Implications for Financial Integrity 48
- B. Capital Structure 51
- C. Implications of Attrition 58
- D. Return on Equity Recommendation 63

Qualifications of William E. Avera ..... APPENDIX A

Constant Growth DCF Model – Electric Utility Proxy Group ..... Attachment WEA-1

Sustainable Growth Rate – Electric Utility Proxy Group ..... Attachment WEA-2

Constant Growth DCF Model – Non-Utility Proxy Group ..... Attachment WEA-3

Sustainable Growth Rate – Non-Utility Proxy Group ..... Attachment WEA-4

Capital Asset Pricing Model – Electric Utility Proxy Group ..... Attachment WEA-5

Capital Asset Pricing Model – Non-Utility Proxy Group ..... Attachment WEA-6

Book Value Capital Structure – Electric Utility Proxy Group ..... Attachment WEA-7

Market Value Capital Structure – Electric Utility Proxy Group ..... Attachment WEA-8

DIRECT TESTIMONY OF WILLIAM E. AVERA
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Arizona Corporation Commission (or "Commission") my independent assessment of the fair rate of return on equity ("ROE") for the jurisdictional electric utility operations of Arizona Public Service Company ("APS" or "Company"). In addition, I also examined the reasonableness of APS' capital structure, considering both the specific risks faced by the Company and other industry guidelines. APS has selected a return on equity from the lower end of my reasonable range to be incorporated with the component cost of debt and APS' capital structure to arrive at the overall rate of return that I believe should be applied to the Company's fair value rate base.

A. Summary of Conclusions

Q. WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR APS?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that APS be authorized a fair

rate of return on equity in the range of 11.25 percent to 12.5 percent. My findings were based on the following analyses:

- In order to reflect the risks and prospects associated with APS' jurisdictional utility operations, my analyses focused on a proxy group of twenty other utilities with comparable investment risks;

- Consistent with the fair value rate base standard, and the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;

- Reflecting the fact that investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the discounted cash flow ("DCF") and capital asset pricing model ("CAPM") methods to estimate a fair ROE for these alternative proxy groups. Both of these methods are forward-looking and can be applied under the fair value rate base standard without adjustments:

    - My application of the constant growth DCF model considered four alternative growth measures based on projected earnings growth and the sustainable, "br+sv" growth rate for each firm in the respective proxy groups;

    - After eliminating low- and high-end outliers, my DCF analyses implied a cost of equity of 11.0 percent for the proxy group of electric utilities and 12.7 percent for the group of non-utility companies;

    - My CAPM analyses were based on forward-looking data that best reflects the underlying assumptions of this approach;

    - Application of the CAPM approach implied a cost of equity of 12.2 percent for the group of twenty comparable risk electric utilities and 11.1 percent for the firms in the non-utility proxy group;

    - Based on these results, I concluded that a reasonable range for the cost of equity for APS is in the 11.25 percent to 12.5 percent range.

Considering investors' expectations for capital markets and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, I concluded that APS' requested ROE of 11.5 percent is reasonable. Based on my evaluation, I determined that:

- Because APS' requested ROE of 11.5 percent falls below the midpoint of my recommended range, it represents a conservative estimate of investors' required rate of return under the fair value rate base standard;
- The reasonableness of an 11.5 percent ROE for APS is also supported by the need to consider APS' weakened credit standing:
  - The pressures of funding significant capital expenditures, increased regulatory and operating risks, and the potential for continued regulatory lag heighten the uncertainties associated with APS;
  - Given APS' present ratings, an inadequate rate of return imposed in this proceeding would further pressure APS' financial flexibility and credit standing;
  - Rating agencies have warned of a possible downgrade to APS' credit standing going forward, which would place the Company in the same category as speculative, or "junk" securities.
- Given the economic reality that APS' actual returns have fallen systematically short of the allowed ROE, even on an original cost basis, let alone a fair value basis; this recommendation assumes that the Commission accepts an adjustment for attrition to give APS an opportunity to actually earn 11.5 percent; and
- The ROE estimates developed in my testimony, as well as the weighted cost of capital requested by APS, can and should be applied to fair value rate base, without adjustment, since the estimation methods are forward-looking and based on returns required on market values.

Q. HOW DID YOU CONDUCT YOUR ANALYSIS OF THE COST OF EQUITY SO THAT THE RESULT CAN BE APPLIED TO THE FAIR VALUE RATE BASE WITHOUT ADJUSTMENT?

A. I implemented the DCF and CAPM methods using forward-looking expectations applied to current market values that are consistent with a fair value rate base standard. My DCF approach used expected dividend yields and forecasted growth rates based on professional security analysts' current expectations. My application of the CAPM was based on expected dividend yields and growth forecasts underlying the expected return on the broad market. I did not employ risk premium estimates based on historical returns nor did I reference comparable earnings on original cost investment. By using forward-looking approaches that estimate the cost of equity based on current market values, the resulting reasonable ROE range is consistent with my understanding of the constitutional requirements in Arizona. Thus, the 11.5 percent return that APS selected from the lower end of my reasonable range can be applied under the fair value rate base standard without further adjustments.

Q. IS ATTRITION A LEGITIMATE CONSIDERATION IN ESTABLISHING APS' RATES FOR ELECTRIC UTILITY SERVICE?

A. Yes. Regulatory lag is prevalent in Arizona and attrition remains a major concern of the investment community. Absent an adjustment for attrition, such as that proposed by APS, the Company will be denied an opportunity to earn its authorized ROE. My testimony demonstrates that:

- APS is undertaking a huge capital investment program in order to meet the growing requirements of customers. Continued regulatory lag will prevent the Company from achieving timely cost recovery, which would erode the Company's credit metrics and result in rating downgrades;

- Setting rates at a level that considers the impact of attrition and allows the utility an opportunity to actually earn its authorized ROE is consistent with fundamental regulatory principles:

- To be fair to investors and to benefit customers, a regulated utility must have an opportunity to actually earn a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk;
- Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation;
- Denying APS the opportunity to earn a sufficient return through the impact of attrition is the economic equivalent of taking the capital value of existing investors.

- The adjustment proposed by APS represents a logical approach to attenuate the impact of attrition.

Q. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that a common equity ratio of approximately 54 percent represents a reasonable basis from which to calculate APS' overall rate of return. This conclusion was based on the following findings:

- APS' requested capitalization is consistent with the Company's need to strengthen its credit standing and financial flexibility as it seeks to raise additional capital to fund significant system investments and meet the requirements of its growing service territory;
- APS' proposed common equity ratio is consistent with the range of capitalizations maintained by the firms in my utility proxy group;
- My conclusion is reinforced by the investment community's focus on the need for greater equity to accommodate higher operating risks and the pressures of funding significant capital investments, as well as the impact of off-balance sheet commitments such as purchased power agreements;
- Regulatory support for higher equity levels is necessary to maintain APS' financial flexibility and preserve the Company's capacity to fund investments that will ensure reliable service and facilitate further development of electric utility infrastructure in Arizona.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR RECOMMENDATION IN THIS CASE?

A. My recommendation was reinforced by the following findings:

- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;

- APS must compete for investors' capital with other utilities and non-utility businesses of comparable risk. If the Company is not provided an opportunity to earn a return that is sufficient to compensate for the underlying risks, investors will be unwilling to supply capital;

- Investors are aware of the near-term challenges posed by upward pressure on costs and rising capital expenditures. Providing APS with the opportunity to earn a return that reflects these realities is an essential ingredient to maintain the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs;

- Strengthening APS' financial integrity is imperative to ensure that the Company has the capability to maintain an investment grade rating while confronting the pressures associated with funding substantial infrastructure development and ensuring APS' ability to respond effectively to unforeseen events.

B. Qualifications

Q. WHAT ARE YOUR QUALIFICATIONS?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had

responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission ("FCC"), the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in 39 states, including the ACC.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in

hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Appendix A.

C. Overview

Q. WHAT IS THE ROLE OF THE RATE OF RETURN IN SETTING A UTILITY'S RATES?

A. The rate of return compensates investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's rate of

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923). In this and other citations of cases, I am not rendering a legal opinion since I am not an attorney. My interpretation is based on my understanding as an economist and financial analyst.

[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). The Arizona Supreme Court has found that the *Hope* case cannot be interpreted to require a particular rate base to violate the Arizona Constitution which provides for a fair value rate base in *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145 (1956).

return, and the allowed return on equity (ROE) should be sufficient to (1) fairly compensate the utility's investors, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the organization, finances, and operations of APS from my participation in prior proceedings before the ACC. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to APS and its parent company, Pinnacle West Capital Corporation ("Pinnacle West"). I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required rate of return for APS, and they form the basis of my analyses and conclusions.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first reviewed the operations and finances of APS, as well as general conditions in the electric utility industry. With this as a background, I described the conceptual principles underlying investors' required rate of return and then conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the DCF approach and

CAPM. From the cost of equity range indicated by my analyses, a rate of return on equity was selected taking into account the fair value rate base standard used in this jurisdiction and the economic requirements and specific risks and potential challenges for APS' electric utility operations in Arizona.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to my analyses, this section briefly reviews the operations and finances of APS, along with the risks and prospects for the utility industry. An understanding of these fundamental factors is essential in developing an informed opinion about investor expectations and requirements that form the basis of a fair rate of return.

A. Arizona Public Service Company

Q. BRIEFLY DESCRIBE APS.

A. The principal subsidiary of Pinnacle West, APS is primarily engaged in the generation, transmission, and distribution of electric power to more than a million customers in 11 of Arizona's 15 counties, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. In addition to providing retail electric utility service, the Company also sells electric power at wholesale to municipalities and other utilities. During the adjusted test year, retail energy sales amounted to 28.8 million megawatt-hours ("MWh"). Sales to residential customers comprised approximately 51 percent of retail revenues from base rates, while sales to non-residential customers comprised approximately 49 percent of retail revenues from base rates.[3] In addition, APS had total

[3] APS Rate Filing, Schedule H-2.

depreciable assets of approximately $11.9 billion,[4] with operating revenues totaling approximately $2.9 billion.[5]

The Company owns approximately 6,158 MW of generating facilities, including its 29.1 percent interest in the three nuclear units of the Palo Verde Nuclear Generating Station ("Palo Verde"), with a total capacity of approximately 1,147 MW. In 2007, nuclear generation accounted for approximately 24 percent of the electric energy provided by APS, with coal at 40 percent, and natural gas at 20 percent. In addition to its own generating capacity, APS relied on purchased power for the remaining 16 percent of its 2007 energy needs. APS' transmission and distribution facilities consist of over 18,000 pole miles of overhead lines and over 16,000 miles of underground lines.

The Company's retail electric operations are subject to the jurisdiction of the Commission, with transmission operations being regulated by FERC. Additionally, APS' nuclear facilities are subject to licensing and oversight by the Nuclear Regulatory Commission ("NRC"). While the Commission originally approved rules to restructure Arizona's electric utility industry in 1999, it effectively halted this process following the Western energy crisis in 2000-2001. Although future legal and regulatory developments surrounding industry restructuring remain uncertain, at the time of this filing there are no active retail competitors providing unbundled energy or other utility services to APS' customers.

[4] Ibid, Schedule A-4.
[5] Ibid, Schedule E-2.

Q. DOES APS ANTICIPATE THE NEED TO ACCESS THE CAPITAL MARKETS GOING FORWARD?

A. Most definitely. APS will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric generation, transmission and distribution facilities. APS' service area is one of the fastest growing regions in the U.S. and the Company anticipates continued population growth expansion with a corresponding increase in required facilities and electric demand over the next ten years. In order to keep pace with customer growth and enhance utility infrastructure, APS anticipates annual construction expenditures to be in the range of $1 billion over the next several years. As Fitch recently noted, "APS is in the midst of a major investment cycle," and "significant external financing, both debt and equity, will be required to fund the program."[6] Support for APS' financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

Q. HOW ARE FLUCTUATIONS IN APS' OPERATING EXPENSES CAUSED BY VARYING FUEL AND POWER MARKET CONDITIONS ACCOMMODATED IN ITS RATES?

A. APS recovers variations in purchased power and fuel costs through a power supply adjustor ("PSA"). Under the PSA, the base fuel rate is established based on annual projections for the following year filed with the Commission. Monthly differences between the actual costs for purchased power and fuel and the base fuel rate are deferred for future recovery or refund. At year-end, the deferred balance is either charged to or credited back to customers over the coming year. As a result, deviations in actual versus projected costs are

[6] Fitch Ratings, Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Credit Analysis* (Jan. 23, 2008).

collected on a one-year lagged basis. In the event that APS experiences unexpected volatility in power costs, it can apply to the Commission for consideration of a mid-year surcharge to address extenuating circumstances.

The PSA continues to provide for a sharing mechanism, under which APS must (with some exceptions) absorb the first 10 percent of costs above the base fuel rate and may retain the first 10 percent of savings when actual costs fall below projected levels. Adjustments are limited to the sum of the prior year's total PSA plus or minus $0.004 per kilowatt-hour ("kWh"), with additional amounts being recorded in a balancing account for future recovery.

Q. WHAT CREDIT RATINGS HAVE BEEN ASSIGNED TO APS?

A. Currently, APS is assigned a corporate credit rating of "BBB-" by Standard & Poor's Corporation ("S&P"). Moody's Investors Service ("Moody's") has assigned the Company an issuer rating of "Baa2", with Fitch Ratings Ltd. ("Fitch") assigning a "BBB-" issuer default rating. Citing the pressures of funding significant capital expenditures, increased regulatory and operating risks, and the potential for continued regulatory lag, Moody's and Fitch have both assigned a "negative" outlook to the Company, informing investors of a possible downgrade going forward.[7] The "BBB-" ratings assigned by S&P and Fitch represent the lowest rung on the ladder of the investment grade scale, and any further downgrade would place the Company in the same category as speculative, or "junk" securities.

B. Utility Industry

[7] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Research* (Dec. 17, 2007); Fitch Ratings Ltd., Fitch Revises Pinnacle West's Outlook to Negative; Affirms 'BBB-'IDR," *Press Release* (Dec. 21, 2007).

Q. WHAT GENERAL CONDITIONS HAVE RECENTLY CHARACTERIZED THE UTILITY INDUSTRY?

A. Over the past decade, the industry has experienced significant structural change resulting from market forces and legislative and regulatory initiatives. At least initially, this process was largely driven by regulatory reforms at the federal level. The Energy Policy Act of 1992 greatly increased prospective competition for the production and sale of power at the wholesale level, with the FERC being an aggressive proponent for actions designed to foster greater competition in markets for wholesale power supply. More recently, in response to the passage of the Energy Policy Act of 2005 ("EPAct"),[8] FERC approved rules establishing incentive-based rate treatments to further promote wholesale competition through participation in transmission organizations and encouraging greater capital investment in electric utility infrastructure.[9]

Most market observers agree that, while "open access" to FERC-jurisdictional transmission facilities has resulted in more competition, it has also introduced substantial risks – particularly for utilities that participate in wholesale energy markets.

Q. HOW HAVE INVESTORS' RISK PERCEPTIONS FOR FIRMS INVOLVED IN THE ELECTRIC UTILITY INDUSTRY EVOLVED?

A. Implementation of structural change and related events caused investors to rethink their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis in the West wreaked havoc on regional energy markets and had dramatic repercussions for investors and utilities nation-

---

[8] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[9] Promoting Transmission Investment Through Pricing Reform, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), order on reh'g., Order No. 679-A, FERC Stats. & Regs. ¶31,236 (2006), order on reh'g. and clarify., Order No. 679-B, 119 FERC ¶ 61,062 (2007) (codified at 18 C.F.R. §§ 35.34-35.).

wide. Beyond causing regulators and legislators in many states – including Arizona – to re-evaluate industry restructuring plans for the retail sector, the financial implications of the Western experience demonstrated the risks facing the electric power industry.

Q. WAS THERE A CORRESPONDING IMPACT ON THE INDUSTRY'S CREDIT STANDING?

A. Yes. The years following the Western power crisis witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. For example, during 2002, S&P recorded 182 downgrades in the utility industry, versus only fifteen upgrades,[10] while Moody's downgraded 109 utility issuers and upgraded three.[11] Credit quality continued to decline during 2003, with S&P reporting that downgrades outpaced upgrades by more than fifteen to one in the fourth quarter of 2003.[12] S&P reported that the majority of the companies in the utility sector now fall in the triple-B rating category and noted a continued negative bias in the credit outlook.[13]

Q. IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING CONCERN FOR INVESTORS?

A. Most definitely. Investors recognize that the prospect of further turmoil in energy markets cannot be discounted. S&P has reported continued spikes in wholesale market prices since the Western power crisis,[14] with Fitch noting that

---

[10] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).
[11] Moody's Investors Service, *Credit Perspectives* (Jul. 14, 2003) at 33.
[12] Standard & Poor's Corporation, "U.S. Utilities' Ratings Decline Continued in 2003, But Pace Slows," *RatingsDirect* (Feb. 2, 2004).
[13] Standard & Poor's Corporation, "U.S. Electric Utilities Continued Their Long Shift To Stability In Third Quarter," *RatingsDirect* (Oct. 23, 2007).
[14] Standard & Poor's Corporation, "Fuel and Purchased Power Cost Recovery In The Wake Of Volatile Gas And Power Markets – U.S. Electric Utilities To Watch," (Mar. 22, 2006).

"elevated energy commodity prices" contribute to a "challenging environment" for electric utilities.[15] Similarly, the FERC Commission Staff has continued to recognize the ongoing potential for market disruption in the West, as a 2007 market assessment report concluded:

> Prices are likely to remain a concern. Last year we monitored transaction above the $400 per megawatt hour Western soft cap due to scarcity at peak. Given the likelihood of higher-priced natural gas in the West this year, extreme weather could easily raise prices to the peak level again in summer 2007.[16]

The report noted that other regional electricity markets were experiencing double-digit price increases and expressed ongoing concern regarding tight supply and congestion.[17] FERC continues to warn of load pockets vulnerable to periods of high peak demand and unplanned outages of generation or transmission capacity and ongoing reliability concerns led FERC to establish mandatory standards for the bulk power system.[18]

In recent years utilities and their customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.[19] S&P concluded that "natural gas prices have proven to be very volatile" and warned of a "turbulent journey" due to the uncertainty associated with future fluctuations in energy costs.[20] Fitch also highlighted the challenges

---

[15] Fitch Ratings, Ltd., "U.S. Power and Gas 2007 Outlook," *Global Power North American Special Report* (Dec. 15, 2006) at 1.

[16] Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, "Summer Energy Market Assessment 2007," (May 17, 2007) at 14.

[17] *Id.* at 4 and 15.

[18] *See Open Commission Meeting Statement of Chairman Joseph T. Kelliher,* Items E-13: Mandatory Reliability Standards for the Bulk-Power System (Docket No. RM06-16-000) (March 15, 2007).

[19] For example, the Energy Information Administration reported that the average price of gas used by electricity generators (regulated utilities and non-regulated power producers) spiked from an average price of $7.18 per Mcf for the first eight months of 2005 to over $11.00 per Mcf in September and October (http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_ nus_m.htm).

[20] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

that fluctuations in commodity prices can have for utilities and their investors, concluding, "Historically high and volatile commodity prices will continue to affect nearly the entire power and gas sector."[21]

In addition, while coal and nuclear power have historically provided relative stability with respect to fuel costs, rising prices for these energy sources have raised investors' concerns. In an article entitled "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," S&P noted that:

> More recently, several current and structural developments for the coal mining industry have resulted in a dramatic increase in spot coal prices.[22]

The Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy, reported that average delivered coal prices for electric utilities increased 9.7 percent in 2006, the sixth consecutive annual rise.[23] Similarly, the EIA documented an increase of 30 percent in the weighted-average price paid for uranium oxide equivalent over 2006.[24] At the same time, heightened environmental awareness, particularly over carbon and other emissions, has increased exposure to mandated remediation and other compliance costs. The imperative of meeting evolving emissions standards implies significant capital expenditures for those utilities, such as APS, that rely significantly on coal-fired generation.

---

[21] Fitch Ratings, Ltd., "U.S. Power and Gas 2007 Outlook," *Global Power North American Special Report* (Dec. 15, 2006) at 1.
[22] Standard & Poor's Corporation, "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," *RatingsDirect* (Aug. 12, 2004).
[23] Energy Information Administration, *Annual Coal Report 2006* at 9 (Nov. 2007).
[24] Energy Information Administration, *2006 Uranium Marketing Annual Report* (May 16, 2007).

Q. DOES THE PSA COMPLETELY ELIMINATE THE RISK ASSOCIATED WITH FLUCTUATIONS IN POWER SUPPLY COSTS?

A. No. The current PSA is viewed as supportive of the Company's financial integrity and an example of constructive regulation, but it does not apply to 100 percent of APS' power costs. Moreover, even for utilities with permanent energy cost adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is recovered from ratepayers. The PSA does not insulate APS from the need to finance deferred power production and supply costs, with Moody's observing that the Company's financial metrics have been negatively impacted as a result.[25]

Even with an energy cost adjustment mechanism, investors recognize the ongoing potential for regulatory disallowances. As S&P observed in a 2004 report:

> [Fuel and purchased power adjustment mechanisms (FPPA)] vary substantially in their ability to protect utilities daily and under catastrophic market movement. Moreover, it is critical to note that FPPAs are not a substitute for supportive regulation; the regulator's ability to disallow costs through ex-post prudency review, regardless of the existence of a FPPA, is a fact of life for utilities.[26]

The PSA provides that the Commission or Commission Staff may review the prudence of fuel and power purchases at any time and all costs flowed through the adjustor are subject to refund if the Commission later determines that the amounts were not prudently incurred.

---

[25] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Opinion* (Dec. 17, 2007).

[26] Standard & Poor's Corporation, *Utilities & Perspectives* (Oct. 18, 2004).

Q. HAVE INVESTORS RECOGNIZED THAT ELECTRIC UTILITIES FACE ADDITIONAL RISKS BECAUSE OF THE IMPACT OF INDUSTRY RESTRUCTURING ON TRANSMISSION OPERATIONS?

A. Yes. As S&P recently affirmed, "The U.S. electric power industry is embarking on a period of rapid change."[27] Mirroring this trend, policy evolution in the transmission area has been wide reaching. Investors' focus on regulatory change in their assessment of risks and prospects was recognized early on by S&P:

> The FERC is in the process of changing every aspect of the electric utility landscape, with industry sages anticipating further transmission and wholesale market development guidance, which could affect the segment's credit prospects and quality. ... Uncertainty will exist until operating rules are in place and have stabilized.[28]

More recently, S&P confirmed a "continued lack of clarity from lawmakers and regulators on the regulatory framework surrounding transmission projects."[29] Transmission operations have become increasingly complex and investors have recognized that difficulties in obtaining permits and uncertainty over the adequacy of allowed rates of return have contributed to heightened risk and fueled concerns regarding the need for additional investment in the transmission sector of the electric power industry.

At the same time, the development of competitive wholesale power markets has resulted in increased demand for transmission resources. Concerns regarding the need to encourage further investment in the transmission sector were exemplified by FERC's *Order Nos. 679* and *679-A*,[30] which established

---

[27] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).
[28] Standard & Poor's Corporation, "Electric Transmission at the Starting Gate," *RatingsDirect* (May 10, 2002).
[29] Standard & Poor's Corporation, "Capital Spending On Electric Transmission Is On The Upswing Around The World," *RatingsDirect* (Aug. 7, 2006).
[30] Promoting Transmission Investment through Pricing Reform, Order No. 679, 116 FERC ¶ 61,057 (July 20, 2006); Order No. 679-A, 117 FERC ¶ 61,327 (Dec. 22, 2006).

incentive-based rate treatments to promote investment in electric utility infrastructure. While there is little debate that increased investment in the transmission system will be required to fully realize the benefits of effective wholesale power markets, the challenges posed by an increasingly complex marketplace heighten the uncertainties associated with transmission operations while requiring the commitment of significant new capital investment to maintain and enhance service capabilities.

Q. WHAT OTHER CONSIDERATIONS AFFECT INVESTORS' EVALUATION OF APS?

A. Utilities are confronting increased environmental pressures that could impose significant uncertainties and costs. S&P cited environmental mandates, including emissions, conservation, and renewable resources, as among of the top ten credit issues facing U.S. utilities.[31] Similarly, Moody's noted that "considerable uncertainty" accompanied any assessment of the future requirements associated with environmental compliance,[32] and cited the exposures associated with environmental compliance in evaluating the credit risks of APS.[33]

While customers benefit from the advantages of fuel cost savings and diversity that nuclear power confers, investors also associate nuclear facilities with risks that are not encountered with other sources of generation. In evaluating an investment in the Company, investors would also consider the fact that Palo Verde accounts for approximately 18 percent of APS' company-owned generation capacity.

---

[31] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).
[32] Moody's Investors Service, "Regulatory Pressures Increase For U.S. Utilities," *Special Comment* (March 2007).
[33] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Research* (Dec. 17, 2007).

Q. ARE THESE UNCERTAINTIES THE ONLY RISKS BEING FACED BY APS?

A. No. Apart from these factors, the industry continues to face the normal risks inherent in operating electric utility systems, including the potential adverse effects of inflation, interest rate changes, and economic cycles. Investors also understand that there is the potential for a significant lag between the time costs are incurred and when they are reflected in rates, and they recognize the ongoing possibility of future cost disallowances. Regulated utilities also continue to face other risks associated with operating a utility system, including the impact of adverse weather and extraordinary risks such as legal liabilities and natural disasters.

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In this section, I develop capital market estimates of the cost of equity. First, I address the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of equity for benchmark groups of comparable risk firms. In recognition of the fair value rate base standard in Arizona, I have applied the DCF and CAPM in a forward-looking manner and I have avoided applying historical risk premium and comparable earnings approaches. Finally, I examine the issue of flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q. WHAT ROLE DOES THE RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance

the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage

on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. Following bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY FOR A UTILITY?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. DID YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF EQUITY FOR APS?

A. No. In my opinion, no single method or model should be relied on to determine a utility's cost of equity because no single approach can be regarded as definitive. As the FCC recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superceded by other

> methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[34]

Therefore, I used both the DCF and CAPM methods to estimate the cost of equity. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that estimates of the cost of equity pass fundamental tests of reasonableness and economic logic. In addition, I applied the DCF and CAPM to two different proxy groups, one based on comparable risk utilities and the other of comparable risk non-utility companies.

B. Discounted Cash Flow Analyses

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

[34] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

Q. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Thus, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY IN RATE CASES?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[35]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

[35] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

The cost of equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. WHAT FORM OF THE DCF MODEL DID YOU USE?

A. I applied the constant growth DCF model to estimate the cost of equity for APS, which is the form of the model most commonly relied on to establish the cost of equity for traditional regulated utilities and the method most often referenced by regulators. Other forms of the general, or non-constant DCF model, such as "two-stage" or "multi-stage" analyses can be used to estimate the cost of equity. However, these approaches generally require several very specific assumptions regarding investors' expected cash flows that must occur at given points in the future. This makes the results of non-constant growth DCF applications sensitive to changes in assumptions, and therefore subject to greater controversy in a rate case setting.

While the complexity of non-constant DCF models may impart an aura of accuracy, there is no evidence that investors' current view of electric utilities anticipates a series of discrete, clearly defined stages. As a result, there is no discernable transition that would support use of the multi-stage DCF approach to evaluate a fair rate of return for APS. Moreover, to the extent that each of these time-specific suppositions about future cash flows do not reflect what real-world

investors actually anticipate, the resulting cost of equity estimate will be biased. Indeed, the benchmark for growth in a DCF model is what investors expect when they purchase stock. Unless we replicate investors' thinking, we cannot uncover their required returns and thus the market cost of equity. In practice, applying a non-constant DCF model would lead to error if it ignores the views of real-world investors.

Q. HOW DID YOU IMPLEMENT THE DCF MODEL TO ESTIMATE THE COST OF EQUITY FOR APS?

A. Application of the DCF model to estimate the cost of equity requires an observable stock price. Because APS is a wholly owned subsidiary of Pinnacle West and has no publicly traded stock, its cost of common equity cannot be estimated directly using the DCF model. In such circumstances, the cost of equity is generally estimated by applying the DCF model to a proxy group of publicly traded companies engaged in similar business activities and the results of that analysis are relied upon to determine the cost of equity for the specific company at issue.

Q. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A. In order to reflect the risks and prospects associated with APS' jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies included by *The Value Line Investment Survey* ("Value Line") in its Electric Utilities Industry groups with: (1) S&P corporate credit ratings between "BBB-" and "BBB+"; (2) a Value Line Safety Rank of "2" or better; (3) a Value Line Financial Strength Rating of "B++" or better; and (4) published growth estimates from Value Line, Thomson Financial

("Thompson"),[36] and Reuters, Inc. ("Reuters"). I excluded two firms that otherwise would have been in the proxy group, but are not appropriate for inclusion because they either do not pay common dividends (*i.e.*, El Paso Electric Company) or are in the process of being acquired by a foreign utility (*i.e.*, Energy East Corporation). These criteria resulted in a proxy group composed of twenty companies. I refer to this group as the "Electric Utility Proxy Group."

Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE THAT INVESTORS WOULD VIEW THE FIRMS IN THE ELECTRIC UTILITY PROXY GROUP AS RISK-COMPARABLE TO APS?

A. Yes. Credit ratings are assigned by independent rating agencies to provide investors with a broad assessment of the creditworthiness of a firm. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors as an objective measure of risk, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity.

Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Given that Value Line is perhaps the most widely available source

[36] Thompson Financial, an arm of The Thompson Corporation, compiles and publishes consensus securities analyst growth rates under the First Call and I/B/E/S brands.

of investment advisory information, its Safety Rank and Financial Strength Rating provide useful guidance regarding the risk perceptions of investors.

The Safety Rank is Value Line's primary risk indicator and ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps.

As discussed earlier, APS is rated "BBB-" by S&P, which indicates slightly greater risk than the "BBB" average rating for the utilities in the Electric Utility Proxy Group. Meanwhile, during the period of my analysis, Value Line assigned Pinnacle West a Safety Rank of "1" and a Financial Strength Rating of "B++"[37] versus averages of "2" and "A", respectively for the Electric Utility Proxy Group. Based on my screening criteria, which reflect objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors, investors are likely to regard this group as having risks and prospects comparable to APS.

[37] As noted earlier, APS is a wholly-owned subsidiary of Pinnacle West. Because Value Line's risk indicators apply to publicly traded common stock, I referenced published values for Pinnacle West in selecting a risk-comparable proxy group. In my opinion, these risk measures are reflective of APS risk.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF EQUITY?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. HOW WAS THE DIVIDEND YIELD FOR THE ELECTRIC UTILITY PROXY GROUP DETERMINED?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the utility proxy group are presented on Attachment WEA-1. As shown there, dividend yields for the firms in the Electric Utility Proxy Group ranged from 1.9 percent to 5.8 percent.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. The next step is to evaluate long-term growth expectations, or "g", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be

used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. ARE HISTORICAL GROWTH RATES LIKELY TO BE REPRESENTATIVE OF INVESTORS' EXPECTATIONS FOR ELECTRIC UTILITIES?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for electric utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the electric utility industry. Moreover, to the extent historical trends for electric utilities are meaningful, they are also captured in projected growth rates, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of electric utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry.[38] As a result of this trend towards a more

[38] For example, the payout ratio for electric utilities fell from approximately 80% historically to on the order of 60%. The Value Line Investment Survey (Sep. 15, 1995 at 161, Dec. 28, 2007 at 695).

conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the electric utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[39]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[40]

---

[39] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).
[40] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

The fact that investment advisory services, such as Value Line, Thompson, and Reuters, focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[41] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[42]

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[43]

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE ELECTRIC UTILITY PROXY GROUP?

A. The earnings growth projections for each of the firms in the utility proxy group reported by Thomson are displayed on Attachment WEA-1. Also presented are the earnings per share (EPS) growth projections reported by Value Line and Reuters.

---

[41] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[42] *Id.* at 88.
[43] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 (March/April 2007) at 56.

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. Based on the assumptions underlying constant growth theory, conventional applications of the constant growth DCF model often examine the relationship between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.[44]

Q. WHAT IS THE PURPOSE OF THE "SV" TERM?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. WHAT GROWTH RATE DOES THE EARNINGS RETENTION METHOD SUGGEST FOR THE ELECTRIC UTILITY PROXY GROUP?

A. The sustainable, "br+sv" growth rates for each firm in the proxy group are summarized on Attachment WEA-1, with the underlying details being presented on Attachment WEA-2. For each firm, the expected retention ratio (b) was

[44] I have included the "bv+sv" growth rate because this growth rate it is often referenced in regulatory circles. Since it uses return on book value equity "r" and theoretically tracks the growth in book value, one could argue that this growth rate is less consistent with the fair value rate base standard of Arizona than professional security analysts' forecasts.

calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. WHAT COST OF EQUITY ESTIMATES WERE IMPLIED FOR THE ELECTRIC UTILITY PROXY GROUP USING THE DCF MODEL?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of equity estimates are shown on Attachment WEA-1.

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT FAIL TO MEET THRESHOLD TESTS OF ECONOMIC LOGIC?

A. Yes. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF range for the Electric Utility Proxy Group must be adjusted to eliminate cost of equity estimates that fail fundamental tests of economic logic.

Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A. Yes. The FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate cost of equity estimates that do not sufficiently exceed this threshold. In a 2000 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC concluded:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[45]

More recently, in its October 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[46]

FERC upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[47]

---

[45] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.
[46] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).
[47] *Id.*

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE ELECTRIC UTILITY PROXY GROUP?

A. The average bond rating associated with the firms in the Electric Utility Proxy Group is triple-B, with Moody's monthly yields on triple-B bonds averaging approximately 6.5 percent in December 2007.[48] As highlighted on Attachment WEA-1, seven of the individual equity estimates for the firms in the Electric Utility Proxy Group exceeded this threshold by 120 basis points or less.[49] In light of the risk-return tradeoff principle and the test applied in *Kern River Gas Transmission Company*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC, these values provide little guidance as to the returns investors require from the common stock of an electric utility.

Q. DO YOU ALSO RECOMMEND EXCLUDING COST OF EQUITY ESTIMATES AT THE HIGH END OF THE RANGE OF DCF RESULTS?

A. Yes. The upper end of the cost of equity range produced by the DCF analysis presented in Attachment WEA-1 was set by a cost of equity estimate of 17.9 percent for Constellation Energy. Compared with the balance of the remaining estimates, this result is an extreme outlier and should also be excluded in evaluating the results of the DCF model for the Electric Utility Proxy Group. This is also consistent with the threshold adopted by FERC, which established that a 17.7 percent DCF estimate for an electric utility was "an extreme outlier" and should be disregarded.[50]

---

[48] Moody's Investors Service, *Credit Perspectives* (Jan 7, 2008).
[49] As highlighted on Attachment WEA-1, these DCF estimates ranged from 6.6 percent to 7.5 percent.
[50] *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

Q. WHAT COST OF EQUITY IS IMPLIED BY YOUR DCF RESULTS FOR THE ELECTRIC UTILITY PROXY GROUP?

A. As shown on Attachment WEA-1 and summarized in Table 1, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 1
DCF RESULTS – ELECTRIC UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
I/B/E/S	11.4%
Value Line	10.9%
Reuters	11.6%
br+sv	9.9%

Q. WHAT DID YOU CONCLUDE BASED ON THE RESULTS OF THE DCF ANALYSES FOR THE ELECTRIC UTILITY PROXY GROUP?

A. Taken together, and considering the relative strengths and weaknesses associated with the alternative growth measures, I concluded that the constant growth DCF results for the Electric Utility Proxy Group implied a cost of equity of 11.0 percent.

Q. HOW ELSE CAN THE DCF MODEL BE APPLIED TO ESTIMATE THE ROE FOR APS?

A. Under the regulatory standards established by *Bluefield*, the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also

applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group."

Q. IS THIS CONSISTENT WITH A FAIR VALUE RATE BASE STANDARD?

A. Yes. My application of the DCF model for utilities used completely forward-looking inputs for dividend yield and growth, which is consistent with a fair value rate base standard. Similarly, reference to the Non-Utility Proxy Group incorporates companies where the original cost of investment is largely irrelevant in determining market performance. Moreover, the economic value of a company's assets in the non-utility sector is dictated by the earnings the assets can generate in the future rather than original cost.[51] Hence, the required return on equity for non-utility companies is a relevant benchmark for the required return on equity under the fair value rate base standard of regulation. By using a DCF model that incorporates forward-looking inputs, the resulting required equity return estimates are kept consistent with the fair value rate base standard applicable in Arizona.

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY PROXY GROUP?

A. To reflect investors' risk perceptions in developing the Non-Utility Proxy Group, my assessment of comparable risk relied on three objective benchmarks for the risks associated with common stocks—Value Line's Safety Rank, Financial Strength rating, and beta. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank and

[51] The U. S. Supreme Court recognized the irrelevance of original cost in the non-utility sector in *Duquesne Light Co. vs. Barasch,* 488 U.S. 299 (1989).

Financial Strength Rating provide useful guidance regarding the risk perceptions of investors. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors.

My comparable risk proxy group was composed of those U.S. companies followed by Value Line that 1) pay common dividends, 2) have a Safety Rank of "1", 2) have a Financial Strength Rating of "A" or above, and 3) have beta values of 0.89 or less.[52] Consistent with the development of my utility proxy group, I also eliminated firms with below-investment grade credit ratings. Table 2 compares the Non-Utility Proxy Group with the Electric Utility Proxy Group and APS across four key indicators of investment risk:[53]

TABLE 2
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
	Credit Rating	Safety Rank	Financial Strength	Beta
Non-Utility Proxy Group	A+	1	A+	0.76
Electric Utility Proxy Group	BBB	2	A	0.89
APS	BBB-	1	A	1.00

Considered along with S&P's corporate credit ratings, a comparison of these Value Line indicators suggests that the investment risks associated with both proxy groups are comparable to, or below those of APS.

[52] This threshold is equal to the average beta for the Electric Utility Proxy Group discussed earlier.
[53] Because APS has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, Pinnacle West. As explained earlier, in my opinion these risk measures are indicative of the risk of APS.

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY PROXY GROUP?

A. As shown on Attachment WEA-3, I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Electric Utility Proxy Group.[54] As summarized in Table 3, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 3
DCF RESULTS – NON-UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
I/B/E/S	12.7%
Value Line	12.6%
Reuters	12.7%
br+sv	12.7%

Q. WHAT DID YOU CONCLUDE BASED ON THE RESULTS OF THE DCF ANALYSES FOR THE NON-UTILITY PROXY GROUP?

A. Taken together, I concluded that the constant growth DCF results for the Non-Utility Proxy Group implied a cost of equity of 12.7 percent. As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles and the fair value rate base standard. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

[54] Attachment WEA-4 contains the details underlying the calculation of the br+sv growth rates for the Non-Utility Proxy Group.

Q. DO YOU BELIEVE THE DCF MODEL SHOULD BE RELIED ON EXCLUSIVELY TO EVALUATE A REASONABLE ROE FOR THE PROXY GROUP OF UTILITIES OR APS?

A. No. Because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is a blunt tool that should never be used exclusively. Regulators have customarily considered the results of alternative approaches in determining allowed returns.[55] It is widely recognized that no single method can be regarded as definitive; all approaches have advantages and shortcomings. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[56]

Moreover, evidence suggests that reliance on the DCF model as a tool for estimating investors' required rate of return has declined outside the regulatory sphere, with the CAPM being "the dominant model for estimating the cost of

[55] For example, a NARUC survey reported that 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996).

[56] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.

equity."[57] *Regulatory Finance: Utilities Cost of Capital* noted the inherent difficulties of the DCF approach:

> [C]aution and judgment are required in interpreting the results of DCF models because of (1) the questionable applicability of the DCF model to utility stocks in certain market environments, (2) the effect of declining earnings and dividends on financial inputs to the DCF model and biases caused by the effect of changes in risk and growth, and (3) the conceptual and practical difficulties associated with the growth component of the DCF model.[58]

The publication concluded, "If the cost of equity estimation process is limited to one methodology, such as DCF, it may severely bias the results."[59]

C. Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity both among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Because investors are assumed to be fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

---

[57] *See e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," Financial Practice and Education (1998).
[58] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* (1994) at 238.
[59] *Id.*

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF EQUITY?

A. Application of the CAPM to the Electric Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Attachment WEA-5. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500 Composite Index (S&P 500).

The dividend yield for each firm was obtained from Value Line, with the growth rate being equal to the average of the earnings growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 354 individual firms, current estimates imply an average growth rate over the next five years of 11.0 percent. Combining this average growth rate with a dividend yield of 2.2 percent results in a current cost of equity estimate for the market as a whole of approximately

13.2 percent. Subtracting a 4.6 percent risk-free rate based on the average yield on 20-year Treasury bonds for December 2007 produced a market equity risk premium of 8.6 percent. Multiplying this risk premium by the average Value Line beta of 0.89 for the Electric Utility Proxy Group, and then adding the resulting 7.6 percent risk premium to the average long-term Treasury bond yield, indicated an ROE of approximately 12.2 percent.

Q. WHAT COST OF EQUITY WAS INDICATED FOR THE NON-UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. As shown on Attachment WEA-6, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group implied a cost of equity of 11.1 percent.

Q. DID YOUR CAPM ANALYSIS RELY ON GEOMETRIC OR ARITHMETIC MEANS IN ARRIVING AT AN EQUITY RISK PREMIUM?

A. No. Reference to arithmetic or geometric mean risk premiums is associated with applications of the CAPM that depend on historical data. In order to derive an estimate of the market equity risk premium under this approach, historical average returns on Treasury bonds are typically subtracted from those for common stocks. These average rates of return based on backward-looking data for historical time periods can be derived using both arithmetic and geometric means.

As discussed above, however, my application of the CAPM was a purely forward-looking approach, which is consistent with the underlying assumptions of this method and the standards underlying fair value rate base. Because I looked directly at investors' current expectations in the capital markets – and not

at historical rates of return – my CAPM analysis made no reference to arithmetic or geometric mean of historical rates of return.

D. Proxy Group Cost of Equity Estimates

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO THE COST OF EQUITY BASED ON YOUR ANALYSES FOR THE PROXY GROUPS?

A. The cost of equity estimates implied by my quantitative analyses are summarized in Table 4 below:

TABLE 4
SUMMARY OF QUANTITATIVE RESULTS

	Cost of Equity Estimates	
Method	**Electric Utility Proxy Group**	**Non-Utility Proxy Group**
DCF	11.0%	12.7%
CAPM	12.2%	11.1%

Based on the results produced by my alternative analyses, I concluded that the cost of equity for the proxy groups of electric utilities and non-utility companies is in the 11.0 percent to 12.7 percent range. Based on my evaluation of the strength of the various methods as they apply to APS, my recommended reasonable range for APS is 11.25 to 12.5 percent.[60]

IV. RETURN ON EQUITY FOR APS

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In addition to presenting the conclusions of my evaluation of a fair rate of return on equity for APS, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital, and evaluates the reasonableness of APS' capital structure.

[60] My professional opinion is that equity flotation costs are appropriately considered in a utility's fair rate of return, but these have not been requested in this case in deference to the commission's findings in the Company's last rate case. *Arizona Corporation Commission*, Decision No. 69663 at 49 (2007).

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW APS AN ADEQUATE RETURN ON FAIR VALUE RATE BASE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While APS remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital. Coupled with the ongoing potential for energy market volatility, APS' plans for infrastructure investment and ongoing exposure to regulatory uncertainty pose a number of potential challenges that might require the relatively swift commitment of significant capital resources in order to maintain the high level of service that customers deserve.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of the pressures associated with large capital expenditure programs and the potential for high and volatile commodity costs in wholesale energy markets. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact. While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on APS. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These

considerations heighten the importance of allowing APS an adequate return on the fair value of its investment.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING ACCESS TO CAPITAL FOR APS?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial to APS' access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. S&P noted that:

> Regulatory rulings have returned to center stage as a dominant factor in assessing companies' credit quality. These decisions will be critical for an industry that in many jurisdictions is nearing the end of extended transition periods and will be making significant capital investment in infrastructure during the next several years.[61]

More recently, S&P concluded, "The political atmosphere will remain highly charged, fostering uncertainty."[62] Moody's echoed these sentiments, observing "regulatory relationships are becoming more important" in an era of broadly rising costs and uncertainties,[63] and concluding:

> [T]here are concerns arising from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief,

---

[61] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric/Gas/Water," *RatingsDirect* (May 3, 2005).
[62] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).
[63] Moody's Investors Service, "Regulatory Pressures Increase for U.S. Electric Utilities," *Special Comment* (March 2007).

> which in turn can increase the likelihood for political and/or regulatory intervention.[64]

With respect to APS specifically, the three major bond rating agencies have all noted the near-term challenges posed by regulatory uncertainty, while explicitly citing the potential that adverse regulatory rulings could further compromise the Company's credit standing.[65] Of particular concern to investors is the impact of regulatory lag and cost-recovery on the APS' ability to earn its authorized ROE and maintain its financial metrics, with Moody's noting:

> The negative outlook is primarily a reflection of APS' continued need for rate increases in a regulatory arena that has historically been challenging. Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating.[66]

S&P concluded, "We view APS' future credit quality as hinging largely on the quality of regulation of electric rates in Arizona."[67]

Moreover, the negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade. In light of APS' present ratings, an inadequate rate of return imposed in this proceeding would further pressure APS' financial flexibility and credit standing.

---

[64] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[65] *See e.g.*, Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (July 11, 2007); Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Research* (Dec. 17, 2007); Fitch Ratings Ltd., "Fitch Revises Pinnacle West's Outlook to Negative; Affirms 'BBB-' IDR" (Dec. 21, 2007).

[66] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Research* (Dec. 17, 2007).

[67] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (July 11, 2007).

Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. While providing a return on fair value that is sufficient to maintain APS' ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* decision, it is also in customers' best interests.[68] Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired and service quality is compromised.

B. Capital Structure

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

[68] The end result requirement of the *Hope* case was affirmed in the *Duquesne* case cited earlier and in the more recent *Verizon Comm. Et al v. FCC*, 535 U.S. 467 (2002).

Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN APS' REQUESTED CAPITAL STRUCTURE?

A. APS' capital structure is presented in the testimony of Witness Dan Kearns. As summarized in his testimony, the common equity ratio used to compute APS' overall rate of return was approximately 54 percent in this filing.

Q. WHAT WAS THE AVERAGE BOOK VALUE CAPITALIZATION MAINTAINED BY THE ELECTRIC UTILITY PROXY GROUP?

A. As shown on Attachment WEA-7, common equity ratios at December 31, 2006 ranged from 39.2 percent to 64.2 percent and averaged 51.9 percent for the firms in the Electric Utility Proxy Group.

Q. WHAT OTHER BENCHMARKS ARE RELEVANT IN ASSESSING APS' CAPITAL STRUCTURE UNDER THE FAIR VALUE RATE BASE STANDARD?

A. To be able to raise capital, companies must pay returns that are competitive at the current market prices of their securities, not the embedded book value of the mix of stocks and bonds. Reference to market values is also consistent with the underlying premise of the fair value rate base standard.[69] As a result, the market value capitalizations for the firms in the Electric Utility Proxy Group also serve as a benchmark in evaluating APS' proposed capital structure.

As shown on Attachment WEA-8, at year-end 2006, the market value capitalizations for the firms in the Electric Utility Proxy Group implied an average common equity ratio of 68.5 percent.

[69] The U.S. Supreme Court in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989) noted that the purpose of fair value ratemaking is to provide a fair return on the market value of plant. Using a market value capital structure would seem to be more consistent with this objective than original cost given that Arizona is a fair value jurisdiction.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE INDUSTRY HAVE FOR THE CAPITAL STRUCTURES MAINTAINED BY UTILITIES?

A. As discussed earlier, the average credit rating associated with firms in the electric industry has fallen to triple-B, the lowest rung on the ladder of the investment grade scale. This decline in credit quality is indicative of the need for utilities to strengthen their balance sheets to deal with an increasingly uncertain and competitive market. A more conservative financial profile is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions. This is especially the case if electric utilities are to be successful in raising the substantial funds necessary to boost investments for network reliability and transmission projects. Moody's recently noted the financial pressures associated with planned infrastructure investments in an environment of rising costs, concluding that:

> [C]ompanies and industries that are facing increasing business and operating risk profiles tend to institute corporate finance strategies that are designed to bolster the balance sheet in an effort to address the rising uncertainties in a more conservative manner.[70]

Moody's went on to warn of the risks associated with increasing debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[71]

---

[70] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).
[71] *Id.*

Q. WHAT CAPITALIZATION IS REPRESENTATIVE FOR THE ELECTRIC UTILITY PROXY GROUP GOING FORWARD?

A. As shown on Attachment WEA-7, Value Line expects that the average book value common equity ratio for the Electric Utility Proxy Group will increase to 52.4 percent over the next three to five years. On a market value basis, the average capitalization for this group of electric utilities implies an average common equity ratio of 64.2 percent (Attachment WEA-8).

Q. HOW DOES APS' COMMON EQUITY RATIO COMPARE WITH DATA FOR THE ELECTRIC UTILITY PROXY GROUP?

A. APS' requested common equity ratio of approximately 54 percent is entirely consistent with the average book value capital structure for the proxy group, based on year-end 2006 data and Value Line's near-term projections. On the other hand, a common equity ratio of 54 percent implies greater financial risk than is indicated based on market values for the Electric Utility Proxy Group.

Q. WHAT OTHER FACTORS SHOULD BE CONSIDERED IN EVALUATING THE COMPANY'S CAPITAL STRUCTURE?

A. Depending on their specific attributes, contractual agreements that obligate the utility to make specified payments may be treated as debt in evaluating a utility's financial risk. Because power purchase agreements ("PPAs") and leases typically obligate the utility to make specified minimum contractual payments akin to those associated with traditional debt financing, investors consider a portion of these commitments as debt in evaluating total financial risks. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. In order to offset the debt equivalent associated with off-balance sheet obligations, the utility must rebalance its capital structure by

increasing its common equity in order to restore its effective capitalization ratios to previous levels.[72]

Reflecting the longstanding perception of investors that the fixed obligations associated with PPAs, leases, and other off-balance sheet obligations diminish a utility's creditworthiness and financial flexibility, the implications of these commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks. For example, in explaining its evaluation of the credit implications of PPAs, S&P affirmed its position that such agreements give rise to "debt equivalents" and that the increased financial risk must be considered in evaluating a utility's credit risks.[73] As the rating agency explained:

> For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.[74]

Apart from reaffirming the importance of imputed debt in its analysis of credit standing, S&P also noted that it has refined its methodology to include imputed debt associated with shorter-term PPAs.[75] Similarly, S&P recently affirmed its

---

[72] The capital structure ratios presented earlier do not include imputed debt associated with power purchase agreements or the impact of other off-balance sheet obligations.
[73] Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007).
[74] *Id.*
[75] *Id.*

policy of modifying a utility's balance sheet to include the debt equivalents associated with operating leases.[76]

As discussed earlier, a significant portion of the Company's power requirements are currently obtained through long-term purchased power contracts. These contractual payment obligations, along with the sale-leaseback agreements associated with Unit 2 of Palo Verde, are fixed commitments with debt-like characteristics and are properly considered when evaluating the financial risks implied by APS' capital structure. S&P recently reported that it adjusts APS' capitalization to include $1.1 billion in imputed debt from off-balance sheet obligations.[77] Unless the Company takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken APS' creditworthiness, implying a higher required rate of return to compensate investors for the greater risks.[78]

Q. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO APS' PROPOSED CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that a capital structure consisting of approximately 54 percent common equity represents a reasonable mix of capital sources from which to calculate APS' overall rate of return. The Company's requested common equity ratio of approximately 54 percent is entirely consistent with the average book value capital structure for the proxy group, based on year-end 2006 data and Value Line's near-term projections. On the other hand, a common equity ratio of 54 percent implies greater financial risk

---

[76] Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008).
[77] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (July 11, 2007).
[78] Apart from the immediate impact that the fixed obligation of purchased power costs has on the utility's financial risk, higher fixed charges also reduce ongoing financial flexibility, and the utility may face other uncertainties, such as potential replacement power costs in the event of supply disruption.

than is indicated based on market values for the Electric Utility Proxy Group. Because the purpose of fair value ratemaking is to provide a fair return on the market value of the utility's rate base, reference to market values is relevant in evaluating APS' capital structure.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

As indicated earlier, the challenges posed by a growing service area, significant capital requirements, volatile energy prices, and reliance on wholesale markets magnifies the importance of preserving financial flexibility. Under these circumstances, it is essential that APS' capital structure include the borrowing capacity necessary to ensure an ongoing ability to fund planned capital investments and meet the Company's service obligations. While financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. In this regard, APS' equity ratio reflects the challenges posed by its resource mix, as well as the burden of significant capital spending requirements.

APS' capital structure reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The

reasonableness of APS' capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the need to accommodate ongoing regulatory risks, and the importance of supporting continued system investment, even during times of adverse industry or market conditions. S&P also noted that its current rating for APS was contingent on the Company's "ability to preserve its capital structure," while Moody's cited the need for a reduction in financial leverage to stabilize APS' credit standing.[79]

C. Implications of Attrition

Q. WHAT CAUSES ATTRITION?

A. Attrition is the deterioration of actual return below the allowed return that occurs when the relationships between revenues, costs, and rate base used to establish rates (e.g., using a historical test year) have changed by the time rates go into effect. For example, if external factors are driving costs to increase more than revenues, then the rate of return will fall short of the allowed return even if the utility is operating efficiently. Similarly, when growth in the utility's investment outstrips the rate base used in the test year, the earned rate of return will fall below the allowed return through no fault of the utility's management. These imbalances are exacerbated as the regulatory lag increases between the time when the data used to establish rates is measured and the date when the rates go into effect.

Q. WHY IS IT NECESSARY TO ADDRESS THE IMPACT OF ATTRITION?

A. Investors are concerned with what they can expect in the future, not what they might expect in theory if a historical test year were to repeat. To be fair to investors and to benefit customers, a regulated utility must have an opportunity

[79] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Research* (Dec. 17, 2007).

to actually earn a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk. In other words, it is the end result in the future that determines whether or not the *Hope* and *Bluefield* standards are met.

Q. HAS THE INVESTMENT COMMUNITY RECOGNIZED THE RISKS ASSOCIATED WITH ATTRITION AND LAG IN ITS EVALUATION OF APS?

A. Yes. S&P noted that the slow pace of regulatory adjustments in Arizona acts as a drag on APS' finances, especially considering the pressures of high growth.[80] Similarly, Moody's warned that a downgrade could result "if APS' regulatory lag for capital spending does not improve," observing "APS' rate case activity is illustrative of an environment where there had tended to be below average assurance of timely recovery of costs and the ability to earn a reasonable return on investment."[81] Fitch also cited the potential that regulatory lag could produce "significant deterioration" in credit metrics and result in rating downgrades.[82] As Fitch concluded:

> The resulting gap between the costs currently being collected in rates and costs incurred could lead to meaningful attrition to APS's earnings, cash flows and credit metrics in 2009. Fitch projects APS's 2008 earned ROE will decline to approximately 6.5%, from an estimated 8.5% in 2007, well below its authorized level of 10.75%.[83]

Fitch observed that failure to adopt an attrition adjustment in APS' last rate proceeding was a "negative development" for the Company and its investors, in light of ongoing capital requirements.[84]

---

[80] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (July 11, 2007).
[81] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Research* (Dec. 17, 2007).
[82] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Credit Analysis* (Jan. 23, 2008).
[83] *Id.*
[84] *Id.*

Q. WHAT ARE THE WAYS TO DEAL WITH ATTRITION?

A. For many utilities, the widespread adoption of pass-through clauses for fuel, purchased power, and other costs that were rising rapidly in the late 1970's and early 1980's helped to offset the impact of attrition. The use of future test years and other forward-looking mechanisms is also useful in ameliorating the impact of attrition, as is accelerated depreciation and inclusion of CWIP in rate base, particularly where financing an expensive generating plant addition is undermining a utility's financial indicators. Many jurisdictions have developed methods to attenuate regulatory lag, such as allowing interim rates, putting rates into effect subject to refund, as well as accelerating the administrative process to allow faster rate decisions. As a result of these measures, combined with the fall-off of inflation, growth, and new construction across the electric utility industry, attrition ceased to be a major regulatory issue by the mid-1980s.

Q. WHY DOES APS FACE ATTRITION?

A. The unique circumstances of APS have led to an attrition problem just as severe as experienced by electric utilities in the turbulent decades of the 1970's and 1980's. APS is contending with customer growth, very significant inflation in basic commodities such as steel, aluminum and copper, and has to finance a huge capital investment program. Regulatory lag is also prevalent in Arizona. While past constructive actions, such as strengthening the PSA, have been helpful in preventing APS' credit ratings from falling below investment grade, attrition remains a major concern of the investment community. All three of the major bond rating agencies have advised investors that APS' ratings could be lowered to speculative grade if the Company is unable to achieve timely regulatory recovery associated with rising costs and burdensome capital expenditure requirements.

Q. IS IT REASONABLE TO CONSIDER AN ADJUSTMENT FOR ATTRITION, SUCH AS THAT PROPOSED BY APS?

A. Yes. Setting rates at a level that considers the impact of attrition and allows the utility an opportunity to actually earn its authorized ROE is consistent with fundamental regulatory principles. That end result would maintain the utility's financial integrity, ability to attract capital and offer investors fair compensation for the risk they bear. Given the past timing of rate relief and the dynamics faced by APS, there is every reason to believe that attrition would lead to under-earning the allowed ROE if APS is not granted an adjustment to counteract the impact of regulatory lag and rising costs and capital requirements.

Q. IS AN ATTRITION ADJUSTMENT CONSISTENT WITH ESTABLISHED STANDARDS OF FAIRNESS?

A. Yes. Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation. The Supreme Court has reaffirmed that the end result test must be applied to the actual returns that investors expect if they put their money at risk to finance utilities.[85] This end result can only be achieved for APS if the allowed return is sufficient to offset the impact of attrition. Thus, whatever the Commission ultimately determines to be investors' required return, the only way to achieve that end result is to make an attrition adjustment sufficient to give APS an opportunity to actually earn that ROE in the future.

---

[85] *Verizon Communications, et al v. Federal Communications Commission, et al*, 535 U.S. 467 (2002). While I cannot comment on the legal significance of this case, I found the economic wisdom of looking to the reasonable expectations of actual investors compelling. I understand that as a fair value state, Arizona law may have requirements beyond the *Hope* and *Bluefield* end-result tests. But economic logic and common sense confirm that a utility cannot attract capital on reasonable terms if investors expect future returns to fall short of those offered by comparable investments.

Indeed, not allowing the Company an opportunity to earn a sufficient return is the economic equivalent of taking the capital value of existing investors.

Q. HOW DOES NOT ALLOWING APS AN ACTUAL OPPORTUNITY TO EARN ITS COST OF CAPITAL RESULT IN TAKING VALUE FROM APS INVESTORS?

A. In real world capital markets, investors have many competing places to put their money. If the money that is dedicated to utility public service does not have an opportunity to earn a return commensurate with that available from alternatives of equivalent risk in the capital markets, investors are not being adequately compensated for the use of their money and bearing risk. Since the capital dedicated to utility service cannot be withdrawn from public service, its economic value to investors is reduced by the amount necessary to make the utility investment competitive with alternative investments on the open market.[86] This reduction in economic value necessary to bring the rate of earnings on utility investment into line with market opportunities of commensurate risk constitutes a taking of investors' capital by the governmental authority setting rates.

We can observe how inadequate returns reduce economic value in the marketplace. Consider a bond issued by a risky entity. Generally the bond is sold to the public at close to face value ($1000) and can be traded in the market.

[86] Individual owners of utility bonds and stocks can sell their claims on future cash flows to other investors, but they cannot withdraw the underlying capital from the utility. The government will not allow capital that is invested in utility rate base to be withdrawn. Therefore, the governmental authority having control over the rates must be set them as to allow that capital to earn of return that is competitive with the earnings available other opportunities of commensurate risk. Failing to allow such a return constitutes a taking of the economic value of the capital dedicated to public utility service.

Whoever owns the bond will receive the coupon payments over the life of the bond and receive the $1000 principal repayment at maturity. As the level of interest rates vary or the risk of the cash flow promises from the issuer of the bond change, so will the market value of the bond. If the risk increases that the promised payments will not be made in full, the value of the bond drops in the capital market. Only by lowering the price that investors must pay for the bond can the expected return be made competitive with other opportunities in the capital markets. If an investor owns the bond and does not sell it when the risk increase, the economic value of their investment is reduced as the market price declines.

Similarly, capital that is dedicated to public service in the rate base of APS has its value affected by the risks and prospects of APS relative to other opportunities in the capital market. Since the money invested in APS' fair value rate base cannot be withdrawn, the effect of not having an opportunity to earn returns commensurate with the underlying risk causes the economic value of its securities to fall. This reduction in value due to an inadequate opportunity to earn a return commensurate with risk is the economic equivalent of the government taking value from the private property of investors without compensation.

D. Return on Equity Recommendation

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. Reflecting the fact that investors' required return on equity is unobservable and no single method should be viewed in isolation, I used both the DCF and CAPM methods to estimate a fair ROE for APS. These methods were applied in a forward-looking manner to be consistent with the Arizona fair value rate base standard. In order to reflect the risks and prospects associated with APS'

jurisdictional utility operations, my analyses focused on a proxy group of twenty-four other utilities with comparable investment risks. Consistent with the fair value rate base standard, and the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy.

My application of the constant growth DCF model considered four alternative growth measures based on projected earnings growth and the sustainable, "br+sv" for each firm in the respective proxy groups. In addition, I evaluated the reasonableness of the resulting DCF estimates and eliminated low- and high-end outliers that failed to meet threshold tests of economic logic. My CAPM analyses were based on forward-looking data that best reflects the underlying assumptions of this approach. The results of my alternative analyses were summarized earlier in Table 4, which is reproduced below:

TABLE 4
SUMMARY OF QUANTITATIVE RESULTS

	Cost of Equity Estimates	
Method	**Electric Utility Proxy Group**	**Non-Utility Proxy Group**
DCF	11.0%	12.7%
CAPM	12.2%	11.1%

Based these findings, I concluded that the cost of equity for the proxy groups indicated by my analyses is in the 11.0 percent to 12.7 percent range. Based on my evaluation of the relative risk and strengths of the analyses, I found the reasonable range for the cost of equity to APS to be 11.25 percent to 12.5 percent.

Q. WHAT THEN IS YOUR OPINION REGARDING THE REASONABLENESS OF THE 11.5 PERCENT ROE REQUESTED BY APS?

A. As explained above, I concluded that the fair rate of return on equity range for APS was 11.25 percent to 12.5 percent. Considering capital market expectations, the potential exposures faced by APS, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that 11.5 percent represents conservative estimate of a fair and reasonable ROE on fair value rate base for APS. In view of the economic reality that APS' actual returns have fallen systematically short of the allowed ROE, my recommendation assumes that there is an adjustment for attrition so that APS has an opportunity to actually earn its 11.5 percent ROE.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

Director, Economic Research Division,
Public Utility Commission of Texas
(Dec. 1977 to Aug. 1979)

Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.

Manager, Financial Education,
International Paper Company
New York City
(Feb. 1977 to Nov. 1977)

Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 250 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 41 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (86 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by

Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

CONSTANT GROWTH DCF MODEL

ELECTRIC UTILITY PROXY GROUP

	(a)	(a)		(b)	(c)	(d)	(e)	(f)	(f)	(f)	(f)
	Dividend Yield			Growth Rates				Cost of Equity Estimates			
Company	Recent Price	Dividends	Yield	IBES	VL EPS	Reuters	br+sv	IBES	VL EPS	Reuters	br+sv Growth
ALLETE	$ 37.36	$ 1.68	4.5%	5.0%	10.5%	8.8%	7.2%	9.5%	15.0%	13.2%	11.7%
Alliant Energy	$ 40.44	$ 1.46	3.6%	6.0%	5.0%	6.3%	3.7%	9.6%	8.6%	9.9%	7.3%
Ameren Corp.	$ 51.00	$ 2.54	5.0%	5.9%	2.5%	7.9%	2.7%	10.9%	7.5%	12.9%	7.7%
Constellation Energy	$ 103.07	$ 2.00	1.9%	16.0%	14.5%	13.0%	12.1%	17.9%	16.4%	14.9%	14.1%
Entergy Corp.	$ 119.92	$ 3.10	2.6%	10.6%	9.5%	9.5%	6.2%	13.2%	12.1%	12.1%	8.8%
Exelon Corp.	$ 84.61	$ 2.00	2.4%	9.9%	10.5%	10.9%	12.8%	12.3%	12.9%	13.3%	15.2%
FirstEnergy Corp.	$ 76.82	$ 2.20	2.9%	8.8%	9.0%	9.5%	6.6%	11.7%	11.9%	12.4%	9.4%
Great Plains Energy	$ 28.51	$ 1.66	5.8%	3.7%	1.5%	3.0%	4.7%	9.5%	7.3%	8.8%	10.5%
Hawaiian Elec.	$ 22.25	$ 1.24	5.6%	8.5%	1.5%	3.1%	2.6%	14.1%	7.1%	8.7%	8.2%
MDU Resources Group	$ 26.85	$ 0.59	2.2%	8.2%	5.0%	7.4%	7.9%	10.4%	7.2%	9.6%	10.1%
Otter Tail Corp.	$ 33.68	$ 1.19	3.5%	7.7%	5.0%	6.0%	5.4%	11.2%	8.5%	9.5%	8.9%
PG&E Corp.	$ 43.52	$ 1.53	3.5%	9.7%	4.5%	8.6%	5.0%	13.2%	8.0%	12.1%	8.5%
Pinnacle West Capital	$ 41.95	$ 2.19	5.2%	5.7%	3.5%	7.8%	2.2%	10.9%	8.7%	13.0%	7.5%
PNM Resources	$ 18.99	$ 0.94	4.9%	9.5%	3.5%	10.3%	3.4%	14.4%	8.4%	15.2%	8.4%
PPL Corp.	$ 53.90	$ 1.31	2.4%	13.7%	13.0%	14.2%	9.4%	16.1%	15.4%	16.6%	11.8%
Progress Energy	$ 48.18	$ 2.46	5.1%	5.0%	3.5%	4.5%	2.9%	10.1%	8.6%	9.6%	8.0%
Sempra Energy	$ 61.65	$ 1.27	2.1%	7.2%	4.5%	7.0%	8.9%	9.3%	6.6%	9.1%	10.9%
Westar Energy	$ 24.76	$ 1.14	4.6%	5.6%	4.5%	4.6%	4.0%	10.2%	9.1%	9.2%	8.6%
Wisconsin Energy	$ 47.84	$ 1.08	2.3%	8.1%	8.0%	9.2%	6.8%	10.4%	10.3%	11.5%	9.0%
Xcel Energy, Inc.	$ 22.41	$ 0.94	4.2%	6.0%	5.5%	6.0%	4.2%	10.2%	9.7%	10.2%	8.4%
Average (g)								**11.4%**	**10.9%**	**11.6%**	**9.9%**

(a) The Value Line Investment Survey, *Summary and Index* (Jan. 25, 2008).
(b) Thompson Financial, *Company in Context* (retrieved Jan. 17, 2008).
(c) The Value Line Investment Survey (Nov. 9, Nov. 30, & Dec. 28, 2007).
(d) http://stocks.us.reuters.com (retrieved Jan. 21, 2008).
(e) See Schedule WEA-2.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

ELECTRIC UTILITY PROXY GROUP

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections			Historical		Mid-Year					
Company	EPS	DPS	Net Book Value	Net Book Value	Annual Change	Adjustment Factor	"b"	Adjusted "r"	"b x r" growth	"sv" Factor	Sustainable Growth
ALLETE	$3.50	$1.80	$28.75	$21.90	5.6%	1.0272	48.6%	12.5%	6.1%	1.12%	7.2%
Alliant Energy	$2.85	$1.70	$27.50	$22.83	3.8%	1.0186	40.4%	10.6%	4.3%	-0.57%	3.7%
Ameren Corp.	$3.40	$2.54	$36.50	$31.86	2.8%	1.0136	25.3%	9.4%	2.4%	0.29%	2.7%
Constellation Energy	$8.25	$2.80	$46.75	$25.53	12.9%	1.0604	66.1%	18.7%	12.4%	-0.24%	12.1%
Entergy Corp.	$7.80	$3.70	$56.15	$40.45	6.8%	1.0328	52.6%	14.3%	7.5%	-1.30%	6.2%
Exelon Corp.	$5.75	$2.10	$24.25	$14.89	10.2%	1.0487	63.5%	24.9%	15.8%	-2.94%	12.8%
FirstEnergy Corp.	$5.25	$2.50	$38.75	$28.30	6.5%	1.0314	52.4%	14.0%	7.3%	-0.74%	6.6%
Great Plains Energy	$2.25	$1.66	$19.75	$16.70	3.4%	1.0168	26.2%	11.6%	3.0%	1.65%	4.7%
Hawaiian Elec.	$1.50	$1.24	$13.75	$13.44	0.5%	1.0023	17.3%	10.9%	1.9%	0.75%	2.6%
MDU Resources Group	$2.00	$0.72	$19.00	$11.88	9.8%	1.0469	64.0%	11.0%	7.1%	0.87%	7.9%
Otter Tail Corp.	$2.25	$1.25	$21.00	$16.67	4.7%	1.0231	44.4%	11.0%	4.9%	0.50%	5.4%
PG&E Corp.	$3.10	$1.92	$28.45	$20.95	6.3%	1.0306	38.1%	11.2%	4.3%	0.72%	5.0%
Pinnacle West Capital	$3.30	$2.45	$38.65	$34.47	2.3%	1.0114	25.8%	8.6%	2.2%	0.02%	2.2%
PNM Resources,	$1.95	$1.07	$26.35	$22.09	3.6%	1.0176	45.1%	7.5%	3.4%	0.04%	3.4%
PPL Corp.	$4.50	$2.20	$19.75	$13.30	8.2%	1.0395	51.1%	23.7%	12.1%	-2.72%	9.4%
Progress Energy	$3.30	$2.53	$35.05	$32.37	1.6%	1.0080	23.3%	9.5%	2.2%	0.68%	2.9%
Sempra Energy	$5.00	$1.40	$43.50	$28.66	8.7%	1.0417	72.0%	12.0%	8.6%	0.26%	8.9%
Westar Energy	$2.00	$1.28	$22.35	$17.62	4.9%	1.0238	36.0%	9.2%	3.3%	0.74%	4.0%
Wisconsin Energy	$3.75	$1.60	$32.75	$24.70	5.8%	1.0282	57.3%	11.8%	6.8%	0.00%	6.8%
Xcel Energy, Inc.	$1.75	$1.10	$17.25	$14.28	3.9%	1.0189	37.1%	10.3%	3.8%	0.36%	4.2%

(a) The Value Line Investment Survey (Nov. 9, Nov. 30, & Dec. 28, 2007).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

DISCOUNTED CASH FLOW MODEL

NON-UTILITY PROXY GROUP

	(a)	(b)	(a)	(c)	(d)	(e)	(e)	(e)	(e)
		Growth Rates				Cost of Equity Estimates			
Company	Dividend Yield	IBES	VL EPS	Reuters	br+sv	IBES	VL EPS	Reuters	br+sv
Abbott Labs.	2.18%	12.2%	10.0%	10.6%	14.4%	14.4%	12.2%	12.8%	16.6%
Aflac Inc.	1.32%	14.5%	14.0%	14.2%	13.1%	15.8%	15.3%	15.5%	14.4%
Anheuser-Busch	2.65%	8.3%	7.5%	8.7%	25.6%	11.0%	10.2%	11.3%	28.3%
Automatic Data Proc.	2.95%	14.2%	10.5%	13.5%	12.8%	17.2%	13.5%	16.4%	15.8%
Bank of America	6.94%	5.0%	7.0%	7.8%	7.8%	11.9%	13.9%	14.7%	14.8%
Bard (C.R.)	0.62%	14.2%	14.0%	14.3%	11.6%	14.8%	14.6%	15.0%	12.3%
Becton, Dickinson	1.27%	13.2%	12.0%	12.7%	13.4%	14.5%	13.3%	14.0%	14.7%
Brown-Forman 'B'	2.03%	10.5%	12.0%	10.7%	14.8%	12.5%	14.0%	12.7%	16.8%
Coca-Cola	2.19%	9.8%	10.0%	10.1%	10.0%	12.0%	12.2%	12.3%	12.2%
Colgate-Palmolive	1.86%	11.0%	12.0%	11.2%	18.2%	12.9%	13.9%	13.0%	20.1%
Commerce Bancshs.	2.55%	6.3%	4.5%	6.3%	8.2%	8.9%	7.1%	8.8%	10.8%
Gannett Co.	4.62%	2.4%	4.0%	3.3%	7.8%	7.0%	8.6%	8.0%	12.4%
Gen'l Mills	2.87%	8.6%	8.5%	8.7%	7.1%	11.5%	11.4%	11.5%	9.9%
Genuine Parts	3.56%	8.9%	9.0%	8.9%	9.3%	12.5%	12.6%	12.5%	12.9%
Heinz (H.J.)	3.42%	7.9%	8.0%	7.9%	10.6%	11.3%	11.4%	11.3%	14.0%
Hormel Foods	1.90%	9.0%	10.5%	9.1%	12.1%	10.9%	12.4%	11.0%	14.0%
Johnson & Johnson	2.45%	9.1%	8.0%	9.4%	10.3%	11.6%	10.5%	11.8%	12.7%
Kimberly-Clark	3.22%	7.2%	6.5%	7.5%	7.5%	10.4%	9.7%	10.7%	10.7%
Kraft Foods	3.52%	7.3%	5.5%	7.4%	3.9%	10.8%	9.0%	10.9%	7.4%
Medtronic, Inc.	1.05%	13.4%	12.0%	14.0%	12.2%	14.5%	13.1%	15.1%	13.3%
Meredith Corp.	1.49%	11.8%	11.5%	12.7%	9.7%	13.3%	13.0%	14.2%	11.2%
Northrop Grumman	1.88%	13.0%	13.0%	10.2%	7.5%	14.9%	14.9%	12.1%	9.4%
PepsiCo, Inc.	2.08%	10.9%	10.5%	10.9%	9.4%	13.0%	12.6%	13.0%	11.5%
Pfizer, Inc.	5.58%	5.4%	2.0%	7.2%	0.9%	11.0%	7.6%	12.8%	6.5%
Procter & Gamble	2.06%	13.2%	11.5%	13.0%	6.0%	15.3%	13.6%	15.0%	8.0%

DISCOUNTED CASH FLOW MODEL

NON-UTILITY PROXY GROUP

	(a)	(b)	(a)	(c)	(d)	(e)	(e)	(e)	(e)
		Growth Rates				Cost of Equity Estimates			
Company	Dividend Yield	IBES	VL EPS	Reuters	br+sv	IBES	VL EPS	Reuters	br+sv
Reinsurance Group	0.71%	10.5%	11.5%	10.5%	11.3%	11.2%	12.2%	11.2%	12.0%
Sara Lee Corp.	2.87%	7.2%	3.5%	6.8%	11.0%	10.1%	6.4%	9.6%	13.9%
Sysco Corp.	3.17%	13.2%	13.0%	13.1%	12.1%	16.4%	16.2%	16.3%	15.3%
United Parcel Serv.	2.50%	13.1%	8.0%	12.6%	12.9%	15.6%	10.5%	15.1%	15.4%
Wal-Mart Stores	1.85%	12.0%	10.0%	12.3%	9.3%	13.9%	11.9%	14.1%	11.2%
Walgreen Co.	1.14%	13.4%	13.0%	13.4%	13.1%	14.5%	14.1%	14.6%	14.2%
Washington Federal	4.39%	7.7%	9.5%	7.3%	9.0%	12.1%	13.9%	11.6%	13.4%
Washington Post	1.03%	7.2%	6.0%	7.2%	8.0%	8.2%	7.0%	8.2%	9.1%
Wells Fargo	4.75%	10.1%	9.5%	10.1%	10.7%	14.9%	14.3%	14.9%	15.4%
Wrigley (Wm.) Jr.	2.03%	10.6%	9.0%	10.3%	10.7%	12.6%	11.0%	12.4%	12.8%
Average (f)						**12.7%**	**12.6%**	**12.7%**	**12.7%**

(a) www.valueline.com (retrieved Jan. 21, 2008).
(b) Thompson Financial, *Company in Context* (Jan. 17, 2008).
(c) http://stocks.us.reuters.com (retrieved Jan. 21, 2008).
(d) See Schedule WEA-4.
(e) Sum of dividend yield and respective growth rate.
(f) Excludes highlighted figures.

NON-UTILITY PROXY GROUP

SUSTAINABLE GROWTH RATE

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections			Historical		Mid-Year					
			Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
ABT	$4.35	$1.60	$18.05	$9.14	14.6%	1.0679	63.2%	25.7%	16.3%	-1.88%	14.4%
AFL	$5.60	$1.52	$26.90	$16.93	9.7%	1.0463	72.9%	21.8%	15.9%	-2.79%	13.1%
BUD	$3.95	$1.46	$6.80	$5.11	5.9%	1.0286	63.0%	59.7%	37.7%	-12.03%	25.6%
ADP	$3.00	$1.25	$17.20	$9.61	15.7%	1.0726	58.3%	18.7%	10.9%	1.92%	12.8%
BAC	$6.10	$3.00	$40.80	$29.70	6.6%	1.0317	50.8%	15.4%	7.8%	-0.03%	7.8%
BCR	$6.35	$0.86	$32.85	$16.46	14.8%	1.0690	86.5%	20.7%	17.9%	-6.22%	11.6%
BDX	$5.75	$1.60	$30.15	$15.63	14.0%	1.0656	72.2%	20.3%	14.7%	-1.27%	13.4%
BF/B	$5.65	$1.40	$23.20	$12.76	12.7%	1.0597	75.2%	25.8%	19.4%	-4.63%	14.8%
KO	$3.95	$1.84	$13.65	$7.30	13.3%	1.0625	53.4%	30.7%	16.4%	-6.38%	10.0%
CL	$5.00	$2.16	$10.40	$2.32	35.0%	1.1489	56.8%	55.2%	31.4%	-13.15%	18.2%
CBSH	$3.70	$1.15	$30.00	$19.61	8.9%	1.0425	68.9%	12.9%	8.9%	-0.66%	8.2%
GCI	$6.15	$1.96	$53.80	$35.71	8.5%	1.0410	68.1%	11.9%	8.1%	-0.35%	7.8%
GIS	$4.40	$2.00	$19.05	$15.64	5.1%	1.0246	54.5%	23.7%	12.9%	-5.85%	7.1%
GPC	$4.25	$1.90	$23.55	$14.95	9.5%	1.0454	55.3%	18.9%	10.4%	-1.09%	9.3%
HNZ	$3.60	$1.90	$10.45	$5.72	12.8%	1.0602	47.2%	36.5%	17.2%	-6.67%	10.6%
HRL	$3.30	$0.80	$22.10	$13.13	11.0%	1.0520	75.8%	15.7%	11.9%	0.16%	12.1%
JNJ	$5.50	$2.04	$25.95	$13.59	13.8%	1.0646	62.9%	22.6%	14.2%	-3.92%	10.3%
KMB	$5.50	$2.76	$19.00	$13.38	7.3%	1.0351	49.8%	30.0%	14.9%	-7.40%	7.5%
KFT	$2.60	$1.20	$22.65	$17.45	5.4%	1.0261	53.8%	11.8%	6.3%	-2.46%	3.9%
MDT	$4.30	$0.83	$18.45	$9.60	14.0%	1.0652	80.7%	24.8%	20.0%	-7.79%	12.2%
MDP	$4.80	$0.90	$29.45	$17.28	14.3%	1.0665	81.3%	17.4%	14.1%	-4.41%	9.7%
NOC	$7.65	$2.00	$68.75	$48.03	7.4%	1.0358	73.9%	11.5%	8.5%	-1.04%	7.5%
PEP	$4.85	$1.96	$13.15	$9.36	7.0%	1.0340	59.6%	38.1%	22.7%	-13.33%	9.4%
PFE	$2.30	$1.36	$12.25	$9.98	4.2%	1.0205	40.9%	19.2%	7.8%	-6.96%	0.9%
PG	$4.75	$1.90	$32.30	$20.87	11.5%	1.0545	60.0%	15.5%	9.3%	-3.34%	6.0%
RGA	$7.60	$0.50	$65.65	$45.85	7.4%	1.0359	93.4%	12.0%	11.2%	0.05%	11.3%
SLE	$1.20	$0.45	$4.65	$3.61	6.5%	1.0316	62.5%	26.6%	16.6%	-5.62%	11.0%
SYY	$2.70	$1.10	$7.85	$5.36	10.0%	1.0477	59.3%	36.0%	21.4%	-9.25%	12.1%
UPS	$5.40	$2.10	$22.45	$14.47	9.2%	1.0439	61.1%	25.1%	15.3%	-2.40%	12.9%
WMT	$4.65	$1.15	$23.65	$14.91	9.7%	1.0461	75.3%	20.6%	15.5%	-6.17%	9.3%
WAG	$3.15	$0.56	$19.50	$11.20	14.9%	1.0692	82.2%	17.3%	14.2%	-1.11%	13.1%
WFSL	$2.75	$1.00	$19.40	$15.07	6.5%	1.0316	63.6%	14.6%	9.3%	-0.29%	9.0%
WPO	$47.95	$9.80	$482.10	$330.20	7.9%	1.0378	79.6%	10.3%	8.2%	-0.19%	8.0%

NON-UTILITY PROXY GROUP

SUSTAINABLE GROWTH RATE

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections			Historical		Mid-Year					
			Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
WFC	$3.90	$1.44	$22.90	$13.58	11.0%	1.0522	63.1%	17.9%	11.3%	-0.65%	10.7%
WWY	$3.20	$1.38	$14.70	$8.65	11.2%	1.0530	56.9%	22.9%	13.0%	-2.30%	10.7%

FORWARD-LOOKING CAPM

ELECTRIC UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.2%	
Growth Rate (b)	11.0%	
Market Return (c)		13.2%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.6%
Market Risk Premium (e)		8.6%
Proxy Group Beta (f)		0.89
Proxy Group Risk Premium (g)		7.6%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.6%
Implied Cost of Equity (h)		**12.2%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 11, 2007).

(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Standard & Poor's Earnings Guide (Nov. 2007) and www.valueline.com (Retreived Dec. 11, 2007).

(c) (a) + (b)

(d) Average yield on 20-year Treasury bonds for December 2007 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_ Y20.txt.

(e) (c) - (d).

(f) The Value Line Investment Survey (Nov. 9, Nov. 30, & Dec. 28, 2007).

(g) (e) x (f).

(h) (d) + (g).

FORWARD-LOOKING CAPM

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.2%	
Growth Rate (b)	11.0%	
Market Return (c)		13.2%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.6%
Market Risk Premium (e)		8.6%
Proxy Group Beta (f)		0.76
Proxy Group Risk Premium (g)		6.5%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.6%
Implied Cost of Equity (h)		**11.1%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 11, 2007).

(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Standard & Poor's Earnings Guide (Nov. 2007) and www.valueline.com (Retreived Dec. 11, 2007).

(c) (a) + (b)

(d) Average yield on 20-year Treasury bonds for December 2007 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_ Y20.txt.

(e) (c) - (d).

(f) www.valueline.com (retrieved Nov. 21, 2007).

(g) (e) x (f).

(h) (d) + (g).

BOOK VALUE CAPITAL STRUCTURE

ELECTRIC UTILITY PROXY GROUP

	At December 31, 2006 (a)			Value Line Projected (b)		
Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
ALLETE	36.7%	0.0%	63.3%	45.5%	0.0%	54.5%
Alliant Energy	34.4%	5.5%	60.1%	44.5%	4.0%	51.5%
Ameren Corp.	45.7%	1.7%	52.6%	45.5%	1.5%	53.0%
Constellation Energy	51.0%	1.9%	47.1%	41.0%	1.0%	58.0%
Entergy Corp.	51.2%	2.0%	46.8%	49.5%	0.5%	50.0%
Exelon Corp.	47.6%	0.5%	51.9%	45.0%	0.5%	54.5%
FirstEnergy Corp.	53.5%	0.0%	46.5%	48.0%	0.0%	52.0%
Great Plains Energy	41.9%	1.6%	56.4%	50.5%	1.0%	48.5%
Hawaiian Elec.	50.1%	1.5%	48.4%	50.5%	1.5%	48.0%
MDU Resources Group	36.7%	0.4%	62.9%	33.0%	0.5%	66.5%
Otter Tail Corp.	33.8%	2.0%	64.2%	49.0%	1.5%	49.5%
PG&E Corp.	46.4%	1.7%	51.9%	45.5%	1.5%	53.0%
Pinnacle West Capital	48.4%	0.0%	51.6%	49.0%	0.0%	51.0%
PNM Resources	50.9%	0.3%	48.8%	48.0%	0.5%	51.5%
PPL Corp.	58.6%	2.3%	39.2%	48.5%	2.0%	49.5%
Progress Energy	52.2%	0.5%	47.3%	49.5%	0.5%	50.0%
Sempra Energy	40.4%	1.4%	58.2%	37.0%	1.0%	62.0%
Westar Energy	50.0%	0.7%	49.3%	50.0%	0.5%	49.5%
Wisconsin Energy	53.6%	0.5%	45.9%	52.0%	0.5%	47.5%
Xcel Energy, Inc.	53.4%	0.8%	45.8%	52.0%	1.0%	47.0%
Average	**46.8%**	**1.3%**	**51.9%**	**46.7%**	**1.0%**	**52.4%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey, (Nov. 9, Nov. 30, & Dec. 28, 2007).

MARKET VALUE CAPITAL STRUCTURE

ELECTRIC UTILITY PROXY GROUP

	At December 31, 2006			Value Line Projected		
	(a)	(b)	(c)	(a)	(b)	(c)
Company	Debt	Other	Common Equity	Debt	Other	Common Equity
ALLETE	20.9%	0.0%	79.1%	29.3%	0.0%	70.7%
Alliant Energy	23.5%	3.8%	72.7%	33.5%	3.0%	63.5%
Ameren Corp.	32.8%	1.2%	66.0%	39.2%	1.3%	59.5%
Constellation Energy	26.6%	1.0%	72.4%	22.7%	0.6%	76.8%
Entergy Corp.	31.6%	1.3%	67.2%	28.7%	0.3%	71.0%
Exelon Corp.	20.1%	0.2%	79.7%	19.5%	0.2%	80.3%
FirstEnergy Corp.	32.5%	0.0%	67.5%	33.9%	0.0%	66.1%
Great Plains Energy	24.3%	1.0%	74.7%	40.3%	0.8%	58.9%
Hawaiian Elec.	33.1%	1.0%	65.9%	39.8%	1.2%	59.0%
MDU Resources Group	20.5%	0.2%	79.2%	23.8%	0.4%	75.8%
Otter Tail Corp.	21.8%	1.3%	76.9%	42.4%	1.3%	56.3%
PG&E Corp.	27.4%	1.0%	71.6%	31.4%	1.0%	67.6%
Pinnacle West Capital	39.0%	0.0%	61.0%	46.6%	0.0%	53.4%
PNM Resources	42.4%	0.3%	57.3%	46.9%	0.5%	52.6%
PPL Corp.	33.5%	1.3%	65.2%	24.2%	1.0%	74.8%
Progress Energy	41.4%	0.4%	58.1%	39.3%	0.4%	60.3%
Sempra Energy	24.9%	0.9%	74.2%	28.3%	0.8%	70.9%
Westar Energy	40.0%	0.5%	59.4%	44.8%	0.4%	54.8%
Wisconsin Energy	36.1%	0.3%	63.6%	40.3%	0.4%	59.3%
Xcel Energy, Inc.	40.8%	0.6%	58.6%	45.9%	0.9%	53.2%
Average	**30.7%**	**0.8%**	**68.5%**	**35.0%**	**0.7%**	**64.2%**

(a) Debt outstanding computed by multiplying long-term debt ratio by total book capital, both as reported by The Value Line Investment Survey (Nov. 9, Nov. 30, & Dec. 28, 2007).

(b) Balance of other long-term capital not accounted for in long-term debt and common equity ratios.

(c) Market value of common equity computed by multiplying stock price by the number of common shares outstanding, both as reported by The Value Line Investment Survey (Nov. 9, Nov. 30, & Dec. 28, 2007).

Daniel A. Kearns

DIRECT TESTIMONY OF DANIEL A. KEARNS

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

TABLE OF CONTENTS

I. Introduction 1

II. Summary 2

III. APS's Revenue Deficiency and Earnings Shortfall 8

- A. The Impact of Attrition on the Company's ROE 8
- B. Impact of Attrition on the Company's FFO/Debt Ratio 11
- C. The Impact of Attrition on the Company's Revenue Requirement Deficiency 12

IV. Pro Forma Adjustments to Test Year 23

- A. Palo Verde Unit 3 Steam Generator Pro Formas 24
- B. Cholla Generating Station Environmental Projects Pro Formas 26
- C. Yucca Units 5 and 6 Pro Formas 27
- D. Post-Test Year Plant-in-Service Pro Formas 28
- E. Attrition Adjustment Pro Forma 31

V. Key Forecasted Financial Results and Conclusion 32

- A. Summary Schedules 33
- B. Cost of Capital 33
- C. Projected Financial Information 34

Attrition due to Changes in ACC Revenues vs. Expenses ..... Attachment DAK-1

Major Changes in ACC Rate Base and Related Change in Cost of Capital Requirements ..... Attachment DAK-2

ACC Jurisdiction Projected Income Statements ..... Attachment DAK-3

ACC Attrition Income Statement Pro Forma Analysis ..... Attachment DAK-4

Funds From Operations (FFO) to Adjusted Debt Ratio ..... Attachment DAK-5

Palo Verde Unit 3 Steam Generator Rate Base Pro Forma ..... Attachment DAK-6

Palo Verde Unit 3 Steam Generator Income Statement Pro Forma... Attachment DAK-7

Cholla Generating Station Environmental Projects Rate Base Pro Forma ..... Attachment DAK-8

Cholla Generating Station Environmental Projects Income Statement Pro Forma ..... Attachment DAK-9

Yucca Units 5 & 6 Rate Base Pro Forma ..... Attachment DAK-10

Yucca Units 5 & 6 Income Statement Pro Forma ..... Attachment DAK-11

Post Test Year Plant Addition Project Summary ..... Attachment DAK-12

Post Test Year Plant Additions Rate Base Pro Forma ..... Attachment DAK-13

Post Test Year Plant Additions Income Statement Pro Forma ..... Attachment DAK-14

Attrition Income Statement Pro Forma ..... Attachment DAK-15

DIRECT TESTIMONY OF DANIEL A. KEARNS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Daniel A. Kearns. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY ("APS" OR "COMPANY")?

A. I am Director of the Financial Planning Department at Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for preparing the Company's short-range and long-range forecasts of income statement, balance sheet, cash flow, revenue deficiency, funds from operations, and other key financial results.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science Degree in Finance from Indiana University in 1982 and a Master of Business Administration Degree from the University of Arizona in 1984. I joined APS in 1984 as a financial analyst. I have over 20 years of experience performing financial forecasting, planning, and analysis with the Company, with the last 18 years focused on financial management.

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

A. My testimony will measure the significant and growing revenue deficiency that the Company has experienced and will continue to see beyond the December 31, 2007 test year (the "Test Year") through at least year-end 2010, the first full year

that the Company expects rates from this case to be in effect. My testimony will also calculate the impact of this growing revenue deficiency on the Company's earnings and credit metrics. My testimony supports the pro forma adjustments to include the Palo Verde Unit 3 Steam Generator, Yucca Units 5 and 6, and certain environmental projects at the Cholla Generating Station in the Company's rate base and operating expenses for rate-setting purposes. In addition, my testimony sponsors a Post-Test Year Plant Additions pro forma adjustment to include in rate base dollars that the Company had already invested in projects at the end of the Test Year that either have already closed or will have closed to plant-in-service by the time the rate levels set in this case will be in effect. In fact, 21% of the dollars included in the Post-Test Year Plant Additions pro forma relate to projects that had already closed to plant–in-service as of April 30, 2008 – a full month before the Company's updated filing was submitted.

My testimony also supports an additional income statement pro forma adjustment that will, if approved, go a long way towards resolving the Company's increasing revenue shortfall. This proposed adjustment will address attrition in the near term and enable the Company to avoid the need for a perpetual string of rate cases to mitigate the impact of continually lagging rates—rates that do not compensate the Company for its capital investment and increasing operating costs the day they are set. Finally, I sponsor the forecasted portions of the A, D, and F Schedules that are included in the Company's rate application.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony describes the extent to which costs relating to APS's vast capital spending requirement of **one billion dollars per year** (spending that is vital to the Company's ability to meet its load growth and maintain high levels of service reliability in an inflationary cost and high-growth environment) far surpasses APS's revenue growth. This phenomenon has caused and will continue to cause the Company to experience a large revenue deficiency and related earnings shortfall—a shortfall that, as APS Witness Donald Brandt describes, threatens the Company's equity values and credit metrics and limits the Company's ability to fulfill its duty to continue to provide reliable service to APS's growing customer base.

The Company's earnings shortfall is highlighted in Standard Filing Requirement ("SFR") Schedules F-1 and A-2 (information required to be filed by the Arizona Corporation Commission ("ACC" or "Commission"), which plainly demonstrate that, absent rate relief, APS's Total Company return on equity ("ROE") will stand at only 7.8% at year-end 2008, 6.2% by the end of 2009, and 5.4% by year-end 2010—far below the 10.75% ROE authorized by this Commission in Decision No. 69663 (June 28, 2007). To address concerns raised in the Company's last rate case that the financial projections underlying APS's rate application should focus only on items within the Commission's jurisdiction, I have prepared an exhibit—Attachment DAK-3—that mirrors Schedule F-1 in all respects except that it presents the Company's financial projections on an ACC-jurisdictional basis. In other words, the financial projections contained in DAK-3 exclude the impact on rate base of the transmission piece of the Company's operations as well as the impact of what are considered to be "below the line" expenses (expenses for which APS's customers traditionally have not been

asked to pay, such as charitable contributions). As Attachment DAK-3 shows, even on an ACC-jurisdictional basis, the Company's ROE rests at only 8.4% at year-end 2008, 6.3% in 2009, dropping further to 5.4% by year-end 2010, each significantly below what APS has been authorized to earn and what it should be allowed the opportunity to earn. Throughout my testimony, I will refer to the steady erosion of the Company's earnings and ROE in this manner as "attrition."

To measure the impact of attrition, I engaged in a detailed analysis of the Company's projected operating income and expenditures. First, I calculated the Company's projected revenues and operating expenses for 2010, and compared those results to the analogous unadjusted Test Year revenues and expenses in order to measure the change in annual operating income that the Company will experience from the unadjusted Test Year through year-end 2010. I performed these calculations on an ACC-jurisdictional basis, without considering the impact of the Company's other pro forma adjustments and assuming that there was no growth in ACC-jurisdictional rate base after the Test Year.

Next, recognizing that the Company's pro forma adjustments to the Test Year will offset some of the revenue requirement deficiency that my initial calculation captured, I accounted for the impact of each of those pro formas in calculating the remaining attrition-related revenue deficiency. I did this in two ways. First, I reduced my initial attrition-related operating income deficiency calculation by the operating income deficiency solved by the Company's pro forma adjustments to the Test Year income statement. Second, to this number, I added the increased revenue requirement (which includes the required return on investment) related to financing the significant ACC-jurisdictional capital projects that the Company expects to undertake by 2010, but did so only after

reducing the total amount of those capital expenditures by the amount of related costs already captured in the Company's rate base pro formas. The result was a remaining attrition-related revenue requirement deficiency of $83 million in 2010, a number that translates to a $79.3 million revenue requirement deficiency in the Test Year (in other words, a revenue requirement increase of $79.3 million in the Test Year will generate $83 million in 2010). It is important to emphasize that the Company will still suffer this $79.3 million revenue requirement shortfall even if the Commission adopts each of the other pro forma adjustments. For this reason, APS has proposed a $79.3 million attrition pro forma adjustment so that its 2010 revenues will match its 2010 expense and capital cost levels.

Because the Company does not expect new rates to go into effect until late-2009 at the earliest, 2010 (the first full year that new rates will be in effect) is the most appropriate period to measure the impact of attrition and propose adjustments accordingly. In using this timeframe, the Company proposes to set revenue levels that would be effective for calendar year 2010 that match its 2010 expense and capital cost levels. Thereafter, attrition will set in again, but APS will at least start out with rates that are not inadequate on the day that they become effective.

Although I have measured the Company's attrition through 2010, the Company will experience attrition in various degrees for each of the next several years. A similar attrition pro forma calculation looking just through 2009, for example, would amount to $36 million (a number that, again, assumes that the Commission adopts all of APS's non-attrition pro forma adjustments). As this

demonstrates, without adequate rate relief, the magnitude of the Company's attrition problem rises with each passing year.

As APS Witness Donald Brandt describes in his testimony, the existence of attrition—particularly at the increasing levels that APS is now experiencing—has damaging consequences to the Company, its shareholders, and its customers. In fact, as I will demonstrate, with the large capital spending obligations challenging APS over the next several years, the Company's current revenues are confiscatory by any reasonable definition of the term, have a detrimental impact on the Company's ROE, and are far from sufficient to keep it within the investment-grade credit range past the end of 2009. In fact, APS expects that as early as the fourth quarter of 2009—without relief from this Commission—the Company will no longer have the credit metrics to keep it out of the range of "junk" credit status. This forecast is based on the very same financial assumptions and methodology that APS uses for reporting purposes with the Securities and Exchange Committee ("SEC") and for other non-regulatory business purposes.

In order to combat these consequences, APS seeks the Commission's approval of several new pro forma adjustments in setting rate levels, including the inclusion of significant levels of post-test year plant additions in rate base and an attrition pro forma adjustment. My testimony will support these adjustments. Finally, my testimony supports pro forma adjustments to rate base and operating expenses to account for post-test year costs relating to the Palo Verde Unit 3 Steam Generator, Yucca Power Units 5 and 6, and certain environmental expenditures at Cholla Generating Station—major projects that have already been completed and closed to plant-in-service.

My testimony also addresses the projected accounting data required by the Commission's SFRs to support the Company's rate case filing. I sponsor the projected information presented on the following SFR Schedules:

- A-2 through A-5 – Summary Schedules
- D-1 through D-3 – Cost of Capital
- F-1 thru F-4 – Projected Financial Information

In addition, as I previously described, I will provide direct testimony on certain rate base pro forma adjustments made to the Test Year, as reflected on SFR Schedules B-2 and C-2. Specifically, I will be sponsoring the "Total Company" column for the following pro formas on SFR Schedule B-2:

- Palo Verde Unit 3 Steam Generator
- Cholla Generating Station Environmental Projects
- Yucca Units 5 and 6
- Post Test Year Plant Additions

Additionally, I will be sponsoring the "Total Company" columns for the following Income Statement pro formas on SFR Schedule C-2:

- Palo Verde Unit 3 Steam Generator
- Cholla Generating Station Environmental Projects
- Yucca Units 5 and 6
- Post Test Year Plant Additions
- Attrition

APS Witness Jason LaBenz sponsors the historic and actual Test Year information required by those Schedules. APS Witness David Rumolo

jurisdictionalizes the Total Company data to isolate those items that fall within the Commission's regulatory jurisdiction.

III. APS'S REVENUE DEFICIENCY AND EARNINGS SHORTFALL

A. The Impact of Attrition on the Company's ROE

Q. WHAT IS ATTRITION, AND WHY IS IT A PROBLEM?

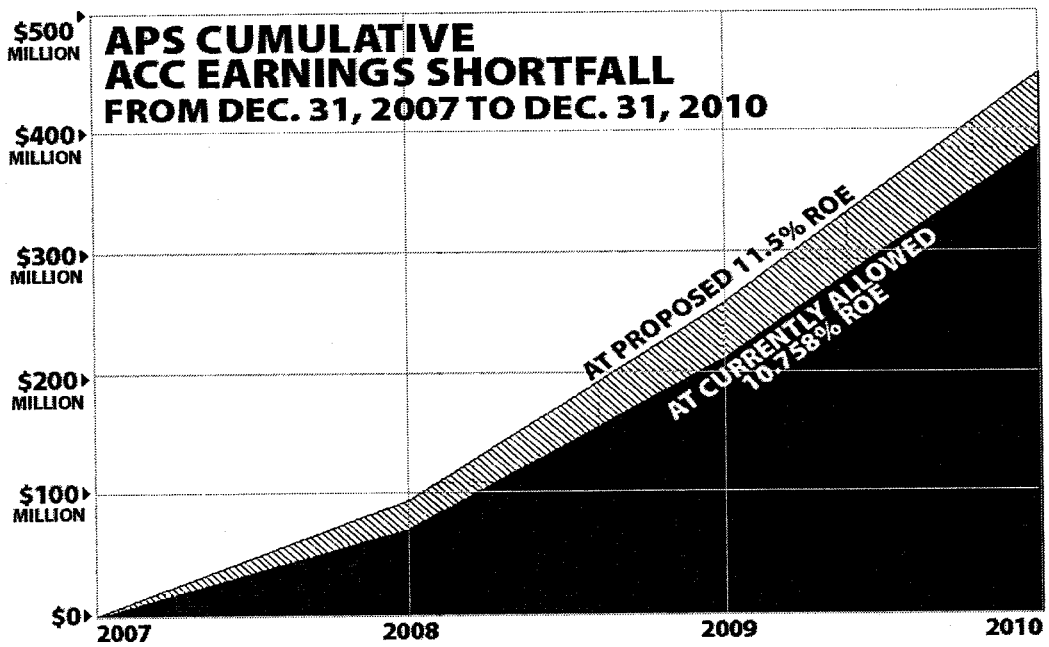
A. Attrition is the erosion of the Company's earnings and earned return over time that occurs when costs, including capital costs, increase faster than revenue growth. In APS's case, the Company is suffering significant attrition due to high construction costs, which expand rate base faster than income, and increasing operation costs—factors that, when coupled with an historic regulatory lag of up to 18 to 24 months between the end of the Test Year until the effective date of new rates, have made it nothing short of impossible for the Company to earn the 10.75% rate of return that this Commission authorized in Decision No. 69663 (let alone the more reasonable 11.5% cost of equity supported by Dr. William Avera in this proceeding).

As the Commission knows, the Company faces a large outlay of capital expenditures necessary to maintain high levels of service reliability to its customers, meet short and long-term load growth, and address pollution control needs. As SFR Schedule F-3 shows in detail, APS is required to invest an average of one billion dollars per year in capital expenditures in 2008, 2009, and 2010. These capital expenditures, along with other increases in expenses, have caused and will continue to cause an imbalance between revenue growth and cost growth over at least the next several years. As a result, the Company is suffering a sizable and growing revenue deficiency, amounting to a loss of

hundreds of millions of dollars, which negatively affects the Company, its shareholders, and eventually its customers.

Q. WHAT IMPACT, IN DOLLARS, HAS ATTRITION HAD ON THE COMPANY'S EARNINGS?

A. Attrition has had a detrimental impact on the Company's earnings. In the last five years (from 2003-2007), APS has suffered a cumulative earnings shortfall of $321 million compared against its allowed ROE, due to costs rising faster than revenue growth. And that shortfall will only increase, absent adequate relief from the Commission. As illustrated in the following graph, APS's projected cumulative ACC-jurisdictional earnings shortfall from the Company's requested 11.5% ROE from December 31, 2007 through December 31, 2010 is over **$450 million**.



Even if measured against the Company's current authorized ROE of 10.75%, the Company's cumulative ACC-jurisdictional earnings shortfall is still over $380 million. Either way you look at it, the Company's earnings attrition is, quite understandably, a serious concern for APS. The earnings shortfall creates intense financial pressure at a time when financing needs are high, and erodes the Company's ROE and other financial metrics that are so crucial to maintaining APS's credit rating within the investment grade range, thus hindering the Company's ability to attract new debt and equity investors.

Q. WHAT IS THE COMPANY'S CURRENT ROE?

A. As shown in Schedule F-1, as of 12/31/07, APS's ROE stood at only 8.7%—205 basis points below what the Commission authorized in APS's last rate case. The Company's ROE does not improve on an ACC-jurisdictional basis. As of the end of the weather-normalized Test Year, APS was earning an ACC-

jurisdictional ROE of only 8.6%—215 basis points below what the Commission authorized in Decision No. 69663 and less than the ROE recommended by any party to that proceeding. It is even further below the 11.5% ROE that investors in a company with APS's risks should reasonably expect to earn, as APS Witness Dr. Avera discusses in his testimony.

Q. WHAT IS THE COMPANY'S PROJECTED ROE OVER THE NEXT SEVERAL YEARS IF THE COMMISSION DOES NOT APPROVE SOME FORM OF BASE RATE RELIEF?

A. As Attachment DAK-3 makes clear, without some form of base rate relief, APS's ACC-jurisdictional ROE—already well below authorized levels—falls to 8.4% by year-end 2008, 6.3% by year-end 2009, and falls even further to 5.4% by year-end 2010—**half** of what the Commission authorized in Decision No. 69663. The Total Company picture is similar, with ROE at only 7.8% in 2008, 6.2% in 2009, and 5.4% by 2010, as Schedules F-1 and A-2 make clear.

B. Impact of Attrition on the Company's FFO/Debt Ratio

Q. WHAT IS THE COMPANY'S CURRENT FUNDS FROM OPERATIONS ("FFO") TO TOTAL DEBT RATIO ("FFO/DEBT"), AND WHAT WILL THAT RATIO BE OVER THE NEXT SEVERAL YEARS ABSENT BASE RATE RELIEF?

A. As of December 31, 2007, the Company's FFO/Debt ratio (a calculation described in the testimony of Mr. Brandt) stands at just 18.6%—decidedly on the low end of the 18% to 28% range set by Standard and Poors for the Company's current BBB- credit grade. *See* Attachment DAK-5. Assuming the Company decides and is able to issue $400 million of common equity during 2008, it should be able to keep its FFO to Debt ratio in the 18% to 28% BBB range at the end of 2008. However, even if the Company decides and is able to issue another $300 million of common equity in 2010 (which optimistically assumes that APS could attract equity investors with its weak ROE), without

some significant rate relief, this crucial credit metric still drops to 17.6% at the end of 2009 and 16.6% at the end of 2010—both of which are "junk" levels. On the other hand, if the Company's application is approved and new rates become effective on October 1, 2009, APS's FFO/Debt ratio will rise to 19.1% by year-end 2009 and 20.8% by 2010—within the BBB investment grade range, albeit at the lower end of such range.

Q. HOW DID YOU CALCULATE THESE FFO/DEBT PROJECTIONS?

A. Each of these projections—set forth in Attachment DAK-5— were calculated in a manner that attempted to reproduce as best as possible the similar calculations made by credit ratings agencies examining a company's creditworthiness. Generally, I calculated the Company's FFO/Debt ratio by adjusting the Company's net income to account for major non-cash items (including depreciation, amortization, deferred fuel, deferred income taxes, Allowance for Funds Used During Construction ("AFUDC"), etc.) to get to the "Funds from Operations" numerator, and compared that number to the Company's total debt, which is adjusted to reflect the impact of imputed debt (the "Debt" denominator). These calculations reflect the impact of including imputed debt attributable to power purchase obligations and operating leases, such as the Palo Verde sale and leaseback, because credit agencies routinely make these adjustments in order to present a more accurate picture of the Company's fixed financial obligations.

C. The Impact of Attrition on the Company's Revenue Requirement Deficiency

Q. WHAT IS A "REVENUE REQUIREMENT DEFICIENCY?"

A. Under general regulatory principles, a utility must be permitted to charge rates that, in combination with any other fees, will bring in sufficient revenues to meet

the utility's operating, capital and other costs, and give the utility a reasonable rate of return on the fair value of its property. A "revenue requirement" is a valuation of how much revenue the utility must bring in on an annual basis in order to meet these expenses. It follows, then, that a "revenue requirement deficiency" measures the extent to which the utility's annual revenues under its current rate structure do not cover its costs and allow the utility to earn a reasonable rate of return.

The Company's total ACC-jurisdictional revenue requirement deficiency in this case is $448.2 million. Of this amount, as I will explain, the $79.3 million amount of the attrition pro forma represents a revenue requirement deficiency that is not captured or addressed in the Company's non-attrition pro forma adjustments.

Q. YOU MENTIONED THAT APS'S COSTS HAVE BEEN EXCEEDING AND WILL CONTINUE TO EXCEED ITS REVENUE OVER THE NEXT SEVERAL YEARS, RESULTING IN A GROWING REVENUE REQUIREMENT DEFICIENCY. SPECIFICALLY, HOW MUCH ARE THE COMPANY'S ACC-JURISDICTIONAL REVENUES EXPECTED TO GROW?

A. For the twelve months ending December 31, 2007 to the twelve months ending December 31, 2010, the Company expects that its ACC-jurisdictional revenues remaining after accounting for fuel and purchased power costs will grow by only $73 million, as shown on Attachment DAK-1. As APS Witness Peter Ewen discusses, the Company's customer growth rate has slowed and may continue to slow in the near term, which would reduce the Company's expected revenue growth even further.

Q. WHAT INCREASES IN NON-FUEL COSTS WILL CAUSE AN IMBALANCE BETWEEN REVENUE GROWTH AND COST GROWTH?

A. The most significant cost increases that the Company will experience by the time new rates become effective relate to the massive capital expenditures required by the Company's construction program. As Schedule F-3 shows, APS will spend an average of one billion dollars per year annually on capital projects from the end of the Test Year until 2010. Of that cumulative amount, as noted in Attachment DAK-2, $2.4 billion is for items within the Commission's regulatory jurisdiction. While the Company's line extension policy requires new customers to pay for a portion of that capital expenditure requirement upfront, that amount (treated as a Contribution in Aid of Construction ("CIAC")) is expected under the current customer growth forecast to reduce the Company's capital spending by only $163 million, still leaving the Company with a remaining ACC-jurisdictional capital expenditure requirement of $2.24 billion between now and 2010—a capital spending requirement that increases the Company's financing, depreciation, and property tax costs, and creates a growing imbalance between APS's projected revenues and its costs.

As shown in Attachment DAK-1, the Company expects other cost increases associated with ACC-jurisdictional operational and maintenance ("O&M") costs, book depreciation and amortization expenses, property and other taxes, and financing costs – many of which are related to the Company's significant capital expenditures.

- ACC-jurisdictional book depreciation and amortization expenses are expected to grow by $63 million from the Test Year through the end of

2010, due primarily to additional depreciation on more than $2.24 billion of capital expenditures closing to plant-in-service during this period.

- ACC-jurisdictional property and other taxes are expected to grow by $11 million from the Test Year through year-end 2010, again caused primarily by additional property taxes on more than $2.24 billion of capital expenditures on plant that will be placed in service during this period.
- ACC-jurisdictional O&M expenses are expected to grow by a total of $94 million from the Test Year through year-end 2010, primarily due to inflation, higher customer service costs, increased pension expenses, and higher medical and other benefit costs.
- ACC-jurisdictional financing costs are expected to increase by at least $91.4 million annually by 2010 due to the Company's required capital spending levels (a number that assumes that the rates authorized in this proceeding are based on a revenue requirement that adopts all of the Company's pro forma adjustments to rate base, as I will now describe in more detail).

Q. PLEASE ELABORATE ON WHY APS EXPECTS FINANCING COSTS TO INCREASE BY $91.4 MILLION OVER THE NEXT THREE YEARS.

A. Three factors are considered in computing the Company's financing costs: interest expense, equity return requirements, and income tax expense. As I will describe, each of these three factors increases considerably as a result of the Company's projected construction expenditures and the corresponding change to the Company's rate base.

As described in detail on Attachment DAK-2, the Company's construction expenditures from the Test Year through the end of 2010 have a significant

impact on the Company's ACC-jurisdictional rate base, increasing it by **$2.4 billion** (only $418 million of which is recovered through the Company's non-attrition pro forma adjustments). That number was calculated as follows. As line 1 of Attachment DAK-2 shows, the Company plans to spend over $2.4 billion on ACC-jurisdictional construction projects from the Test Year through 2010, which number is reduced to $2.2 billion when offset by the benefit of the CIAC dollars projected to be brought in from the Company's Schedule 3 line extension policy during that time (which projection may change if customer growth levels deviate from those assumed in this application). For rate base purposes, this number is reduced to $1.1 billion when the rate base benefits of book depreciation and amortization and nuclear fuel amortization expenses on existing and new plant is included in the analysis. The Company's deferred income tax balance is expected to increase by $65 million from the end of the Test Year though 2010, which will result in a corresponding decrease to rate base, as shown on line 9. Summed together, APS expects that its total ACC-jurisdictional rate base will increase by **$1.04 billion** by 2010 because of the Company's necessary capital projects. Only $418 million of that additional rate base is captured in the Company's pro forma rate base adjustments, leaving $626 million of increased rate base unaccounted for (a number that will rise if the Commission rejects any of the Company's rate base pro forma adjustments). That $626 million number is the rate base amount underpinning my attrition calculation.

To calculate the increase in financing costs resulting from this as-yet unaccounted for increase to rate base, I have multiplied the $626 million growth in rate base by the cost of debt and equity and their respective capitalization

ratios. As Attachment DAK-2 lines 13 and 14 show, interest expense increases APS's revenue requirements by $16.7 million through 2010 (using the Company's 5.77% cost of debt and 46.21% debt ratio from the Test Year), and equity return increases revenue requirements by another $38.7 million through 2010 (using the Company's proposed 11.5% cost of equity and its 53.79% equity ratio from the Test Year). The resulting change in interest and equity cost of capital is $55.4 million, which is then converted to a revenue requirement using the revenue conversion factor. As shown on line 17, this conversion results in a change in cost of capital-related revenue requirements of $91.4 million annually by 2010.

Q. HOW DO THE REVENUE AND COST INCREASES YOU HAVE JUST DESCRIBED TRANSLATE INTO A REVENUE DEFICIENCY FROM ATTRITION?

A. An analysis of these increases shows that APS's projected cost increases far exceed its expected revenue growth through 2010, resulting in a $79.3 million dollar revenue deficiency at Test Year levels caused by attrition—a number that assumes that all the other Company's pro forma adjustments (other than its attrition pro formas) are adopted and included in rates. (If the Company's other pro forma adjustments are not accepted, the attrition number rises commensurately.)

To arrive at this $79.3 million attrition-related revenue deficiency, I took a number of steps, each of which is laid out in Attachment DAK-1. As DAK-1 shows, I first compared the Company's projected change in annual revenues and expenses (fuel and purchased power, O&M, book depreciation, property taxes, income taxes, and interest expense) that will occur from the unadjusted Test Year to 2010. That analysis indicates that the Company will experience a $57

million after-tax operating income deficiency between the end of the Test Year and 2010 if rates were set at unadjusted Test Year levels without any pro forma adjustments and assuming that there was no growth in the ACC-jurisdictional rate base after the Test Year.

Next, I accounted for the fact that the Company is proposing income statement pro formas that, if accepted by the Commission, will offset this operating income deficiency and cover some of the Company's revenue and expense growth beyond the Test Year. As Attachment DAK-1 Line 12 shows, the Company's other income statement pro formas increase APS's operating income by $62 million, which – were APS to have no increase in rate base after the unadjusted Test Year – would leave the Company with an operating income "surplus" of $5 million. That $5 million figure converts into an $8 million revenue requirement "surplus" — a revenue requirement that does not yet account for and is woefully short of the massive increase to capital costs related to rate base growth. This greatly worsens APS's already massive budget deficit.

To the operating income analysis, I then accounted for the Company's anticipated rate base growth and added the $91 million revenue requirement deficiency resulting from the Company's projected growth in financing costs to the $8 million operating income revenue requirement "surplus" described above. (As I previously explained, this increase was calculated assuming that the Commission would approve the Company's pro forma adjustments to rate base, bringing the $1.04 billion ACC-jurisdictional increase to rate base that will occur by 2010 down by $418 million to $626 million.) That calculation shows that the Company will experience a total annual ACC-jurisdictional revenue requirement deficiency of $83 million in 2010—a deficiency that is not

addressed in any way by the Company's other pro forma adjustments and that is solely attributable to attrition caused by regulatory lag.

In order to convert this 2010 deficiency to Test Year levels, I adjust it on lines 18 and 19 to account for revenue growth from the Test Year to 2010. (This conversion is captured in the attrition operating income statement adjustment analysis outlined in column i of Attachment DAK-4.) This converts the $83 million annual revenue deficiency to an $79.3 million annual revenue deficiency, using Test Year levels of sales. In other words, an increase of $79.3 million in base rates on adjusted 2007 Test Year sales would produce $83 million in revenues for 2010.

Q. WHAT DOES THE $79.3 MILLION DEFICIENCY ON LINE 19 OF ATTACHMENT DAK-1 INDICATE?

A. The $79.3 million annual revenue deficiency revealed in Attachment DAK-1 shows that even though the Company's revenues are growing, its costs are growing faster—a trend that will continue well into the foreseeable future. In the end, when the Commission considers the growth in fuel and purchased power expense, growth in the cost of capital for the addition of $626 million of ACC-jurisdictional rate base investment not covered in the other rate base pro formas, and the estimated increases to other operating expenses, there still remains a substantial ACC-jurisdictional revenue requirement deficiency resulting from attrition.

Q. PLEASE DESCRIBE THE ASSUMPTIONS YOU USED TO CALCULATE THE COMPANY'S REVENUE DEFICIENCY.

A. As indicated above, I have measured the impact of attrition by analyzing the Company's projected revenue growth compared to its projected operating

expenses for the twelve months ending December 31, 2007 through the twelve months ending December 31, 2010. I have emphasized these years because new rates will likely take effect no earlier than mid-2009 or after, and 2010 would reflect the first full year's impact of those rates. Given the regulatory lag historically attending APS rate cases, it is unlikely that APS would be able to increase its rates again before the end of 2010, even if the Company filed another general rate case as soon as the current proceeding concludes. Thus, by measuring attrition through the 2010 timeframe, the Company proposes to set revenue levels for calendar year 2010 that match its 2010 costs.

The key assumptions underlying the Company's financial projections are shown in Schedule F-4. As that Schedule indicates, the financial projections contained in this Application assume that rates from this case will be effective on October 1, 2009, that the Company decides and is able to access both the debt and equity markets, and that the Commission allows the Company to pass increases to the Transmission Cost Adjustor to retail customers immediately after those increases are approved by the Federal Energy Regulatory Commission ("FERC").

Another key assumption underlying the Company's financial projections is that customer growth will average 1.7% over the years 2008 through 2010. The Company recognizes, however, as explained in Mr. Ewen's testimony, that the Company's customer growth rate has slowed markedly in recent months and may continue to slow in the near-term. While, in the current economic climate, customer growth may slow in the near-term, any such change will not reduce the Company's base rate revenue deficiency. To the contrary (and, perhaps, counter-intuitively), because the Company must prepare for customer growth

well in advance of its arrival, a temporary slowdown in customer growth from assumed levels will reduce the amount of revenue that the Company will receive from new customers without proportionately reducing the non-fuel costs that the Company was required to incur to meet its anticipated demand.

Moreover, as Mr. Brandt describes in his testimony, the Company's capital spending requirements include substantial amounts that are not directly impacted by any slowdown in customer growth (such as power plant maintenance and environmental projects, capitalized nuclear fuel costs, projects intended to maintain the reliability of the Company's distribution system, and projects necessary to maintain the Company's information systems and facilities). As a result, the Company's base rate revenue deficiency may actually *increase* in the near-term if customer growth slows from assumed levels. However, slower customer growth would likely cause the Company's Power Supply Adjustor revenue requirements to be lower than they otherwise would be, thereby partially offsetting the potential impact on the Company's overall revenue requirements.

Q. COULDN'T THE COMPANY'S FORECASTS BE OFF? WHAT IF THE COMPANY'S COST ESTIMATES TURN OUT TO BE TOO HIGH OR TOO LOW?

A. By the nature of forecasting, some revenue streams and individual cost items will prove to be higher than forecasted and some will prove to be lower. Even if it turns out that the Company's 2010 cost growth versus revenue growth gap estimates are too pessimistic by as much as 25%, the Company would still experience an ACC-jurisdictional revenue deficiency of $59.5 million per year ($79.3 million x 75%) caused by attrition. This level of annual deficiency cannot be ignored just because APS cannot predict with 100% certainty what the

exact level of attrition will be. Nor should it be. In fact, the Arizona Administrative Code inherently recognizes the value of projections for rate-setting purposes by requiring the Company to include forecasted information in its rate filing through various SFR schedules, including Schedule F-1, which requires the Company to show its projected ROE through 2010 under both present and proposed rates, and Schedule F-3, which requires the Company to project its capital expenditures through 2010. Were projections such as these irrelevant to the rate setting process, the Commission would not likely require that such information be submitted.

Moreover, with respect to attrition, APS has demonstrated that it has already experienced substantial attrition in the past due to high levels of capital spending and other increased costs, coupled with a historical test year rate-making process and regulatory lag. These conditions will unlikely change going forward, and it is therefore reasonable to assume that the Company will continue to experience similar levels of attrition over the next few years. APS's attrition calculation was premised on the very same growth and cost assumptions that the Company uses for construction planning and other purposes. The Company has a regulatory obligation to invest in and build infrastructure to serve future customers and must prepare to do so years before those customers sign up for service based on similar projections, even though APS does not know exactly how many new customers it will ultimately have to serve. APS should not be forced to incur these costs using projections but be denied even the opportunity to earn its allowed rate of return because its projections may not turn out to be precisely accurate.

IV. PRO FORMA ADJUSTMENTS TO TEST YEAR

Q. DESCRIBE GENERALLY THE PRO FORMA ADJUSTMENTS YOU ARE SPONSORING.

A. First, I support pro forma adjustments to rate base and operating expenses to account for post-test year additions to plant, specifically those relating to the Palo Verde Unit 3 Steam Generator, certain environmental projects at the Cholla Generating Station, and the additions of Yucca Units 5 and 6, located in Yuma, Arizona (APS Witness Patrick Dinkel testifies to the prudency of the costs incurred for the Yucca plant additions). Each of these specific projects, if not already complete, will be completed and closed to plant-in-service well before rates from this case will be in effect.

Second, I support a more general pro forma adjustment to include in rate base all the dollars that the Company has invested in construction projects that were on its balance sheet at the end of the Test Year and that will be completed and closed to plant-in-service by the time rates from this case take effect. In fact, more than 21% of the dollar amount related to these projects had **already** closed to plant in service at the time this application was filed. The 1,200 projects comprising this adjustment, while collectively quite significant, are individually too small and numerous to break out into individual pro formas. In this pro forma, titled "Post-Test Year Plant Additions," I have removed the corresponding balances for the Palo Verde Unit 3 Steam Generator, certain environmental projects at the Cholla Generating Station, and the additions of Yucca Units 5 and 6 that are already captured in other specific Test Year pro formas.

Finally, to cover the remaining deficiency between revenues and costs not rectified by these and the Company's other pro forma adjustments, I sponsor an attrition adjustment that will allow APS to charge rates that will actually give the Company the opportunity to earn its authorized rate of return at least on original cost rate base if not on fair value.

A. Palo Verde Unit 3 Steam Generator Pro Formas

Q. WHY HAS THE COMPANY INCLUDED PRO FORMA ADJUSTMENTS FOR THE REPLACEMENT OF PALO VERDE UNIT 3 STEAM GENERATORS?

A. APS has made pro forma adjustments for its Palo Verde steam generator replacement costs because the costs are known and measurable and the plant related to this project was placed in service on January 19, 2008—just a few weeks after the close of the Test Year and before this case was even filed. Moreover, in the Company's last two rate filings, the Commission approved substantively identical pro forma adjustments to rate base and operating expense for the steam generator replacement of Units 1 and 2.

Like other nuclear generating stations throughout the nation, heat and corrosion have caused damage to the tubes in the Palo Verde steam generators. The Palo Verde owners, including APS, have determined it is both necessary and economically desirable to replace the Palo Verde steam generators and related equipment in each Unit to preserve the Unit's output and to improve the plant's reliability. The Unit 2 steam generators and related equipment were replaced in 2003 and the Commission allowed recovery of those costs in Decision No. 67744 (April 7, 2005). The Unit 1 steam generators and related equipment were replaced in 2005, and the Commission allowed recovery of those costs in Decision No. 69663. In neither instance was this adjustment opposed by any

party. The Unit 3 steam generators are the final set of steam generators being replaced at Palo Verde, and the Company seeks to recover those costs in this proceeding. The Palo Verde pro forma adjustment increases Total Company rate base by $93,860,000. (*See* Attachment DAK-6 and SFR Schedule B-2, page 1, column 2.)

Q. WHAT RELATED COMPONENTS WILL BE REPLACED DURING THE PROJECT FOR PALO VERDE UNIT 3 STEAM GENERATORS?

A. In addition to the two Palo Verde Unit 3 steam generators, three low-pressure turbine rotors, core protection calculators and pressurized heaters are being replaced. Replacement of these items will improve the future reliability and efficiency of Palo Verde Unit 3 and increase its output by approximately 26 megawatts. APS included this 26 megawatt improvement when it calculated the Company's proposed fuel and purchased power expense and off-system margin, as noted in the testimony of Mr. Ewen. Because APS included the benefit of its investment to customers when it calculated these expenses, basic principles of fairness and "matching," as well as prior precedent, require that it also be allowed to recover the costs associated with that investment by including these items in rate base.

Q. HOW WAS THE PALO VERDE UNIT 3 STEAM GENERATORS RATE BASE ADJUSTMENT CALCULATED?

A. The $93.9 million adjustment to rate base required by the steam generator project was calculated using the new steam generator's estimated cost at the time it was placed in service.

Q. HOW MUCH IS THE PRO FORMA ADJUSTMENT TO OPERATING INCOME FOR THE REPLACEMENT OF THE PALO VERDE UNIT 3 STEAM GENERATORS?

A. Taking into account the change in annual book depreciation, property taxes, and higher interest deductions due to the higher rate base, the replacement of the Palo Verde Unit 3 steam generator reduced operating income before income tax by $1,707,000. (*See* Attachment DAK-7 and SFR Schedule C-2, page 1, column 1.)

B. Cholla Generating Station Environmental Projects Pro Formas

Q. WHY HAS THE COMPANY MADE PRO FORMA ADJUSTMENTS FOR THE ADDITION OF CHOLLA CAPITAL ENVIRONMENTAL PROJECTS?

A. These pro forma adjustments encompass several environmental projects that were placed in service at Cholla Generating Station in May of 2008—known and measurable expenses that resulted in plant-in-service just months after the Test Year and before this revised application was even filed. There are several projects at Cholla, all of which are related to necessary environmental improvements. These environmental projects include a Unit 2 NOx abatement, a lime-slacking upgrade, and a slurry disposal installation. Together, APS's pro forma Total Company rate base adjustment related to its Cholla environmental projects totals $15,889,000. (*See* Attachment DAK-8 and SFR Schedule B-2, page 1, column 3.)

Q. BRIEFLY DESCRIBE THESE PROJECTS AND INDICATE WHAT COMPONENTS WILL BE REPLACED AND/OR RETIRED BY THE PROJECT'S COMPLETION.

A. The replacements and retirements for each project are as follows:

- <u>Lime Slaking Upgrade</u> – This is a process whereby dry lime is crushed and mixed with water ("slaked") to make the reagent for use in scrubbers.

- Slurry Disposal – Slurry disposal is needed to remove the lime and SO2 solids from the scrubbers.

- Unit 2 Low NOx Burner – These projects replace existing coal burners in the boiler with burners that are specifically designed to reduce the amount of nitrous oxides (NOx) that are produced when the coal is burned.

Q. HOW WAS THE CHOLLA PROJECTS RATE BASE ADJUSTMENT CALCULATED?

A. The $15.9 million increase in rate base was calculated using the new equipment's estimated cost as of the date on which the equipment was placed into service.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME ADJUSTMENT PRO FORMA FOR THE CHOLLA ENVIRONMENTAL PROJECTS.

A. Taking into account the change in operations and maintenance expense, annual book depreciation, property taxes, and higher interest deductions due to the higher rate base, Total Company operating income before income tax is reduced by $432,000 because of the Cholla environmental additions. (*See* Attachment DAK-9 and SFR Schedule C-2, page 1, column 2.)

C. Yucca Units 5 and 6 Pro Formas

Q. WHY HAS THE COMPANY MADE PRO FORMA ADJUSTMENTS TO ACCOUNT FOR THE CONSTRUCTION OF YUCCA UNITS 5 AND 6?

A. As described in the testimony of APS Witness Dinkel, the Company is building two combustion turbine units at the existing Yucca Generating Station ("Yucca") site in order to increase its generating capacity within APS's Yuma load pocket. The construction of the two new units is expected to be completed and placed into service by the summer of 2008—more than a year before rates from this

case are expected to become effective. As with the additions at Palo Verde and Cholla, APS is seeking recovery of plant additions made at Yucca because those expenses are known and measurable and the plant will be placed in service well before the rates requested in this application are expected to be in effect. The pro forma adjustment increases Total Company rate base by $77,123,000. (*See* Attachment DAK-10 and SFR Schedule B-2, page 2, column 4.)

Q. HOW WAS THE YUCCA UNITS 5 AND 6 RATE BASE PRO FORMA ADJUSTMENT CALCULATED?

A. The Company calculated the $77.1 million increase in rate base using the estimated cost of construction for the two units as of the time when the equipment is expected to be placed into service.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE YUCCA UNITS 5 AND 6 CONSTRUCTION PROJECTS.

A. Taking into account the change in operations and maintenance expense, annual book depreciation, property taxes, and higher interest deductions caused by the higher rate base, Total Company operating income before income tax is reduced by $3,020,000 for the addition of the Yucca Units. (*See* Attachment DAK-11 and SFR Schedule C-2, page 1, column 3.)

D. Post-Test Year Plant-in-Service Pro Formas

Q. WHAT IS THE PURPOSE OF THE POST-TEST YEAR PLANT ADDITIONS PRO FORMA?

A. The purpose of the Post-Test Year Plant Additions pro forma is to include in rate base all the dollars that the Company had already invested in and were on APS's balance sheet at the end of the Test Year that will close to plant-in-service by the time rates in this case will take effect. Unlike the Palo Verde Unit 3 Steam Generator, Cholla, and Yucca projects (which have been removed from the Post-

Test Year Plant Additions pro forma so as to not double count them), these projects are individually too numerous to break out into individual pro formas.

As of December 31, 2007, the Company had incurred $623 million in costs related to utility construction projects to serve existing and future customers that had not been recorded as in-service at the end of the Test Year. After removing the dollars associated with the Palo Verde Unit 3 Steam Generator, the Cholla Capital Projects, Yucca Units 5 and 6, transmission projects, projects of relatively small dollar value, and projects not expected to be placed in service before rates from this case will take effect, $251.3 million Total Company and $244.8 million of items within the Commission's jurisdiction remains for projects that are either already in-service or that will be completed by the expected effective date of new rates. A summary of these projects and their amounts is attached hereto at Attachment DAK-12.

Failing to include these projects in rate base exacerbates APS's attrition problem. When the plant included in this pro forma adjustment is placed in service, the Company must stop accruing its AFUDC on that plant, so the financing costs incurred on that investment will no longer have an offset, thus reducing the Company's earnings. Additionally, the plant will begin to incur depreciation and operating and maintenance expenses. If the Commission does not include those items in rate base, the Company's expenses related to those projects will increase, but the Company will not be permitted to earn any return on them until APS's next rate case. This result heightens the already harmful effect of regulatory lag and drives the Company's already significant earnings shortfall upward.

In the Post-Test Year Plant Additions pro forma, the Company seeks to include an adjustment to rate base to include these amounts for plant that has already closed to plant-in-service or that will have closed by the time rates from this proceeding will become effective, along with the annualized book depreciation and property taxes attributable to this new plant-in-service. The Company does not seek to include in rate base any investment that will not have closed to plant by the effective date of the Company's new rates. APS will submit updated numbers for the Commission's review throughout these proceedings in order to update the amount of this pro forma adjustment to conform to the plant that has closed to plant-in-service as the proceedings progress. Authorizing this adjustment will help produce rates that reasonably match the Company's known and measurable costs at the time rates become effective and thus mitigate the Company's growing revenue deficiency.

Q. HOW MUCH IS THE RATE BASE PRO FORMA FOR POST-TEST YEAR PLANT-IN-SERVICE?

A. The Total Company Post-Test Year Plant-in-Service Pro Forma Adjustment is $251,258,000. Of this amount, $53.2 million had already closed to plant-in-service as of April 30, 2008 – just four months after the Test Year and before this revised application was submitted. As previously noted, this amount does not include balances related to the Palo Verde Unit 3 Steam Generator, the Cholla environmental projects, transmission projects, comparably small projects, or the Yucca Units 4 and 5 projects described above. (*See* Attachment DAK-13 and SFR Schedule B2, page 2, column 5.)

Q. HOW MUCH IS ANNUALIZED BOOK DEPRECIATION ON THE POST-TEST YEAR PLANT-IN-SERVICE?

A. The annualized book depreciation on the $251.3 million of Total Company Post-Test Year Plant-in-Service is $14.1 million annually, which amount is also included in the pro forma. Total reduction to operating income before income tax is $17,348,000. (*See* Attachment DAK-14 SFR Schedule C-2, page 2, column 4.)

E. Attrition Adjustment Pro Forma

Q. WHAT ADDITIONAL ADJUSTMENT TO RATE BASE AND OPERATING INCOME IS APPROPRIATE IF THE COMMISSION ACCEPTS THE COMPANY'S RATE ASKING IN ITS ENTIRETY?

A. If the Commission accepts the Company's entire rate asking—including each of APS's other pro forma adjustments—APS would require an additional adjustment to revenue requirements in the amount of $79,278,000 in order to close the remaining gap between APS's revenue growth and its expense growth that will still exist at the time new rates become effective. As described previously, Attachments DAK-1 and DAK-2 show the major components of revenue and expense increases expected through 2010. This increase, taken together with the Company's other pro forma adjustments, is necessary to provide APS with the opportunity to earn a reasonable rate of return on its investment at the time the new rate is fixed. (*See* Attachment DAK-15 and SFR Schedule C-2, page 2, column 5.)

Because part of the Company's attrition-related revenue requirement deficiency is caused by growth, APS Witness Rumolo has proposed an impact fee to recover part of the revenue requirement for the attrition pro forma rather than passing that amount to base rates.

Q. HOW WOULD AN ATTRITION ADJUSTMENT IMPROVE THE COMPANY'S EARNINGS?

A. The additional $79.3 million per year of revenues would increase earnings by $48 million in 2010, allowing APS's ACC jurisdictional operations to earn a return on average equity of 7.6% in 2009 and 10.8% in 2010, assuming that all of the Company's other pro formas are adopted. This is significantly below APS's requested ROE and produces far less than the return on fair value recommended by Dr. Avera, but it at least approximates the ROE found reasonable by Decision No. 69663. This analysis is shown on Attachment DAK-3.

V. KEY FORECASTED FINANCIAL RESULTS AND CONCLUSION

Q. PLEASE DESCRIBE THE ACCOUNTING INFORMATION CONTAINED WITHIN THE SFR SCHEDULES THAT YOU ARE SPONSORING.

A. With respect to the Company's SFR schedules, my testimony covers the forecasted accounting statements and financial results, many of which I have referred to previously in my testimony. The Total Company data is the same type of information that is disclosed directly or indirectly in both the APS and the consolidated Pinnacle West audited financial statements, each of which are included in filings made with the SEC for historical years. The forecasted information is supplied to investors and filed with the SEC periodically.

Additionally, all of the accounting projections provided in my testimony follow Generally Accepted Accounting Principles ("GAAP"). These are the principles that accounting professionals use to prepare financial statements. One major goal of GAAP is to make financial statements comparable from year to year, from industry to industry, and from jurisdiction to jurisdiction. In addition to

GAAP, APS's accounting practices comply with other applicable utility accounting standards, such as the FERC Uniform System of Accounts, which this Commission has adopted. *See* AAC R14-2-212(G).

The direct testimony of Mr. LaBenz addresses the historical accounting statements and actual Test Year data used in the SFRs. Mr. Rumolo focuses on the jurisdictional allocation of APS revenues, costs and rate base items for the actual Test Year and all the pro forma adjustments.

A. Summary Schedules

Q. PLEASE DESCRIBE THE PROJECTED INFORMATION ON SFR SCHEDULES A-2 THRU A-5.

A. These summary schedules provide the "Summary Results of Operations," the "Summary Capital Structure," the "Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service" and the "Summary Changes in Financial Position" for the Test Year and the prior two calendar years. These schedules also include historical information. I am sponsoring the forecasted data for the Test Year and future calendar years. Mr. LaBenz is sponsoring the historical information on these schedules. The most important financial indicator in the A schedules is the presentation of ROE. As Line 12 of Schedule A-2 shows, if the Company's rate request is granted effective October 1, 2009, Total Company average ROE ends 2009 at 7.3% and ends 2010 at 9.7%.

B. Cost of Capital

Q. PLEASE DISCUSS THE COST OF CAPITAL INFORMATION THAT YOU ARE SPONSORING.

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital. I am sponsoring the forecasted data in this schedule. SFR Schedule D-2 presents supporting detail for the long-term debt summarized on

SFR Schedule D-l. Again, I sponsor the projected data in this schedule. SFR Schedule D-3 addresses preferred stock. Although the Company did not have any outstanding preferred stock as of the end of the Test Year, it has included Schedule D-3 nonetheless for the sake of completeness. SFR Schedule D-4 addresses the Company's cost of common equity, and is sponsored by Mr. LaBenz.

C. Projected Financial Information

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULES F-1 THROUGH F-4.

A. SFR Schedule F-1 presents income statements for projected calendar years, and for actual Test Year results, at present and proposed rates. I sponsor the projected information contained on these schedules, while Mr. LaBenz sponsors the historical and Actual Test Year information.

As I have previously indicated, Schedule F-1, like Schedule A-2, shows important information relating to the Company's actual and projected ROE. As Schedule F-1 shows, under APS's present rates, the Company's ROE falls from 8.7% at the end of the Test Year to 7.8% at year end 2008, to 6.2% and 5.4% respectively in 2009 and 2010—well below any reasonable ROE. The Company's proposed rates would bring the Company's ROE to 7.3% in 2009 and 9.7% by year-end 2010. As DAK-3 shows, the ROE improves when calculated considering only those items that fall within the Commission's regulatory jurisdiction, partly because the ACC-jurisdictional analysis removes all of the Company's below the line expenses. SFR Schedule F-2 shows projected changes in the financial position of the Company for future calendar years and the Test Year, at present and proposed rates. SFR Schedule F-3 presents projected annual construction requirements, by property classification,

for four years subsequent to the Test Year. I sponsor the projected data on this schedule, which shows that APS expects to spend an average of **one billion dollars per year** on capital projects for each of the next three years: $1.023 billion in 2008; $1.085 billion in 2009; and $993.3 million in 2010. Finally, SFR Schedule F-4 presents the key assumptions used in developing projections, which I discussed previously in my testimony.

Q. DO YOU HAVE ANY FINAL COMMENTS?

A. APS's rising costs—both operating costs and those incurred as a result of the Company's large capital spending requirement of one billion dollars per year—are necessary to maintain high levels of service reliability and meet load growth in an inflationary cost environment. As I have described, these cost increases will far surpass APS's revenue growth through 2010. This phenomenon has caused and will continue to cause the Company to experience a revenue deficiency and related earnings and ROE shortfall. In fact, even if the Commission approves each of the Company's non-attrition pro forma adjustments in setting new rates, APS will *still* experience a $79.3 million revenue requirement deficiency related solely to attrition. In order to prevent these consequences, APS asks that the Commission approve all of its several pro forma adjustments in setting rate levels, including the inclusion of significant levels of post-test year plant additions in rate base as well as an attrition pro forma adjustment. Together, these adjustments will address the Company's attrition problem in the near term and will enable the Company to avoid the need for a perpetual string of rate cases to mitigate the impact of continually lagging rates—rates that do not compensate the Company for its capital investment and increasing operating costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Attrition due to Changes in ACC Revenues vs. Expenses from Test Year 12/31/2007 to Projected Calendar Year 2010 (1) (2)
($ in millions)

Line	Changes in:	
1	Revenues (present rates except for TCA increases) (DAK-4, column e, line 1)	$ 242
2	Fuel & purchased power expense (present rates with fuel in base at current 3.25 cents) (DAK-4, col.e)	169
3	Revenues net of fuel and purchased power expense (DAK-4, column e, line 3)	73
4	Operations and maintenance expense (DAK-4, column e, line 4)	94
5	Book depreciation and amortization expense (DAK-4, column e, line 7)	63
6	Property and other taxes expense (DAK-4, column e, line 10)	11
7	Operating income before income taxes and cost of capital (DAK-4, column e, line 12)	(95)
8	Interest expense (DAK-4, column e, line 13)	1
9	Taxable income (DAK-4, column e, line 14)	(96)
	Income tax rate =	39.36%
10	Income taxes (does not include income tax on increased cost of capital revenue requirements which can be seen on DAK-2 line 17 minus line 15)	(38)
11	Operating income deficiency (line 7 - line 10)	(57)
12	Operating income deficiency covered by other income statement pro formas (from DAK-4, columns -f + g, line 16)	62
13	Operating income surplus before changes in cost of capital revenue requirements and adjustment for lines 17 through 19 below (matches DAK-4, column h, line 16)	5
14	Revenue conversion factor (schedule C-3)	1.6491
15	Revenue requirement surplus before changes in cost of capital revenue requirements on rate base	8
16	Revenue requirement deficiency from changes in cost of capital on major changes in ACC rate base from 12/31/2007 to 12/31/2010 not covered by other pro formas (see attachment DAK-2, line 17)	(91)
17	Total ACC revenue requirement deficiency in calendar 2010 not covered by other pro formas due to attrition from revenue growth shortfall vs. expense growth	(83)
		/
18	Adjustment to convert 2010 revenue deficiency to a test year 12/31/2007 revenue deficiency (adjust for projected 5% sales growth from 2007 (with July 2007 rates annualized) to 2010)	105%
19	Total ACC revenue requirement deficiency measured in test year dollars not covered by other pro formas due to attrition from revenue growth shortfall vs. expense growth (83-79 = 4m reduction in revenue requirement deficiency shown in DAK-4, column i, line 1)	(79)

(1) revenue increase is assumed to be effective October 1, 2009 or thereafter, so 2010 was used so as to match expense levels with revenue levels for the first full year the new rates would be in effect

(2) excludes changes in revenues and expenses related to the renewable energy standard requirements (RES) and demand side management (DSM)

Major Changes in ACC Rate Base from 12/31/2007 To 12/31/2010 and Related Change in Cost of Capital Revenue Requirements ($m)

Line		2008	2009	2010	Totals from 12/31/2007 to 12/31/2010
1a	**ACC construction expenditures (includes nuclear fuel and excludes transmission)**	**$ 825**	**$ 810**	**$ 770**	**$ 2,405**
1b	- Projected schedule 3 fees treated as CIAC	**25**	**59**	**79**	**163**
1c	= **Net ACC construction expenditures**	**800**	**751**	**691**	**2,242**
2	+ AFUDC debt and equity	32	28	26	86
3	- Increase or (decrease) in CWIP balance	(6)	(128)	77	(57)
4	= **Closings to plant in service (A)**	**838**	**907**	**640**	**2,385**
5	Book depreciation & amortization on income statement (1)	356	378	405	1,139
6	+ Nuclear fuel amortization in fuel expense on income statement	33	40	64	137
7	= **Growth in accumulated book depreciation and amort. (B)**	**389**	**418**	**469**	**1,276**
8	**Change in net plant = (A) - (B)**	**449**	**489**	**171**	**1,109**
9	- Change in deferred taxes	48	26	(9)	65
10	= **Major changes in ACC rate base from 12/31/2007 to 12/31/2010**	**$ 401**	**$ 463**	**$ 180**	**$ 1,044**
11	- **ACC rate base changes covered by other pro formas** (schedule B-2, page 4, column n)				(418)
12	= **Remaining major changes in ACC rate base not covered in rates**				**626**

Change in Cost of Capital Revenue Requirements due to Major Changes in ACC Rate Base from 12/31/07 to 12/31/2010:

13	**Change in interest expenses** **$626 x 5.77% cost of debt (from schedule D-1, page 2) x 46.21% debt ratio =**	**16.7**
14	**Change in equity return** **$626 x 11.50% cost of equity (from schedule D-1, page 2) x 53.79% equity ratio =**	**38.7**
15	**Total change in cost of capital**	**55.4**
16	**Revenue conversion factor** (schedule C-3)	**1.6491**
17	**Change in cost of capital revenue requirements due to major changes in ACC rate base from 12/31/2007 to 12/31/2010 not covered by other pro formas**	**$ 91.4**

(1) excludes $6m annual reduction to income statement amortization expense for the amortization of the 2.64% interest rate premium on the loan from APS to PWEC which was retired in 2005. Amortization ends April 2010.

ARIZONA PUBLIC SERVICE COMPANY
ACC JURISDICTION
PROJECTED INCOME STATEMENTS
PRESENT RATES AND WITH PROPOSED RATE INCREASE
(Dollars in Thousands)

Line No.	Description	Projected Year Present Rates Year Ending 12/31/2008	Projected Year Present Rates Year Ending 12/31/2009	Projected Year Present Rates Year Ending 12/31/2010	Projected Year Proposed Rates Year Ending 12/31/2009	Projected Year Proposed Rates Year Ending 12/31/2010	Line No.
1.	Electric Operating Revenues	$ 3,035,635	$ 3,035,259	$ 3,166,327	$ 3,136,762	$ 3,420,304	1.
2.	Fuel and Purchased Power	1,352,167	1,320,008	1,402,588	1,358,204	1,363,962	2.
3.	Operating Revenues Less Fuel Expenses	1,683,468	1,715,251	1,763,739	1,778,558	2,056,342	3.
	Other Operating Expenses:						
4.	Oper & Maint excluding fuel expenses *	734,751	775,848	814,968	775,848	814,968	4.
5.	Deprec & Amort	350,440	371,791	402,620	368,342	391,509	5.
6.	Income Taxes	114,075	113,146	94,128	139,527	216,371	6.
7.	Other Taxes	112,272	120,514	121,764	120,514	121,764	7.
8.	Operating Income	371,930	333,952	330,259	374,327	511,730	8.
	Other Income (Deductions):						
9.	Income Taxes	(524)	(93)	(5)	(41)	469	9.
10.	Allowance for equity funds used during construction	18,083	15,553	14,237	15,553	14,236	10.
11.	Other Income	1,965	260	14	112	(1,255)	11.
12.	Other Expenses	(314)	0	0	0	0	12.
13.	Total	19,210	15,720	14,246	15,624	13,450	13.
14.	Income Before Interest Deductions	391,140	349,672	344,505	389,951	525,180	14.
	Interest Deductions						
15.	Interest on long-term debt	137,473	148,222	167,030	148,263	162,408	15.
16.	Interest on short-term borrowings	17,968	7,668	11,313	7,342	9,018	16.
17.	Debt discount, premium and expense	3,321	3,366	3,484	3,366	3,472	17.
18.	Capitalized interest	(13,893)	(12,415)	(11,364)	(12,415)	(11,364)	18.
19.	Total	144,869	146,841	170,463	146,556	163,534	19.
20.	Net Income	$ 246,271	$ 202,831	$ 174,042	$ 243,395	$ 361,646	20.
21.	% Return on Average Common Equity	8.4%	6.3%	5.4%	7.6%	10.8%	21.
22.	Average Common Equity	2,946,834	3,212,373	3,208,510	3,208,630	3,338,903	22.

Notes:
* Includes expenses related to Renewable Energy Standard and Demand Side Management programs

12/31/2007 To 12/31/2010 ACC Attrition Income Statement Pro Forma ($000)

Line		12/31/2007 Test Year Before Pro formas ACC a (1)	2010 Forecast ACC b (2)	Change From 12/31/2007 Test Year to 2010 ACC c (b-a)	Remove Change in RES & DSM ACC d (3)	Operating Income Gross Attrition 12/31/2007 to 2010 (Excluding RES & DSM Change) ACC e (c+d)	Operating Income Attrition Solved by Other Pro formas ACC f (4)	Remove Impact of Fuel & Purchased Power Pro forma ACC g (5)	Operating Income Net Attrition 12/31/2007 to 2010 in 2010 ACC h (e-f+g)	Convert 2010 Rev. Req. to a 12/31/2007 Test Year Rev. Req. ACC i (6)	Operating Income Net Attrition 12/31/2007 to 2010 in Test Year ACC j (h+i)
1	Electric Operating Revenues	$2,855,173	$3,166,328	$ 311,155	$ (69,596)	$ 241,559	$(123,265)	$ -	$ 364,824	$ 4,000	$ 368,824
2	Purchased Power and Fuel Costs	1,222,435	1,402,588	180,153	(11,115)	169,038	81,361	116,684	204,361	-	204,361
3	Oper Rev Less Purch Pwr & Fuel Costs	1,632,738	1,763,740	131,002	(58,481)	72,521	(204,626)	(116,684)	160,463	4,000	164,463
	Other Operating Expenses:										
4	Operations Excluding Fuel Expense	662,862	814,968	152,106	(58,481)	93,625	(18,118)	-	111,743	-	111,743
5	Maintenance	-	-	-	-	-	-	-	-	-	-
6	Subtotal	662,862	814,968	152,106	(58,481)	93,625	(18,118)	-	111,743	-	111,743
7	Depreciation and Amortization	328,872	391,509	62,637	-	62,637	16,304	-	46,333	-	46,333
8	Amortization of Gain	-	-	-	-	-	-	-	-	-	-
9	Administrative and General	-	-	-	-	-	-	-	-	-	-
10	Other Taxes	110,411	121,764	11,353	-	11,353	17,157	-	(5,804)	-	(5,804)
11	Total	1,102,145	1,328,241	226,096	(58,481)	167,615	15,343	-	152,272	-	152,272
12	Operating Income Before Income Tax	530,593	435,499	(95,094)	-	(95,094)	(219,969)	(116,684)	8,191	4,000	12,191
13	Interest Expense	158,309	159,605 (7)	1,296	-	1,296	(15,396)	-	16,692 (8)	-	16,692
14	Taxable Income	372,284	275,894	(96,390)	-	(96,390)	(204,573)	(116,684)	(8,501)	4,000	(4,501)
15	Current Income Taxes Rate : 39.36%	146,531	108,592	(37,939)	-	(37,939)	(87,093)	(45,927)	3,227 (9)	1,574	4,801
16	Operating Income (line 12 - line 15)	$ 384,062	$ 326,907	$ (57,155)	$ -	$ (57,155)	$(132,876)	$ (70,757)	$ 4,964	$ 2,426	$ 7,390

Line		
17	Revenue conversion factor (schedule C-3)	1.6491
18	Revenue surplus before cost of capital revenue req. on rate base growth	12,187
19	ACC rate base growth thru 2010 (DAK-2, line12)	626,000
20	Cost of capital (schedule D-1, p.2)	8.86%
21	Revenue conversion factor (schedule C-3)	1.6491
22	Revenue deficiency on rate base	(91,465)
23	ACC attrition revenue deficiency	(79,278)

(1) From C-1, page 2 of 2, with transmission OATT expense of $103,576 moved from O&M to fuel and purchased power to be comparable to the 2010 forecast
(2) From attachment DAK-3, ACC jurisdictional F-1, 2010 present rates column with depreciation reduced $11.112m for depr. study impacts.
(3) Assumes a $54,596 change in EPS/RES revenue from $12,000 in the test year (which includes $6m in base rates) to $66,596 in 2010.
Assumes a $15,000 change in DSM adjuster revenues from $0 in the test year to $15,000 in 2010.
(4) Sum of all the ACC income statement pro formas in Schedule C-2, page 12, less the attrition pro forma
(5) Removed 90% of the $129,649 base fuel and purchased power pro forma, since it gets offset by reduced psa revenues, and therefore doesn't contribute to reducing attrition
(6) From DAK-1, line 19 minus line 17
(7) ACC rate base after pro formas $5,359.964m (schedule B-1, page 1, line 19) + major changes in ACC rate base through 2010 $626m (DAK-2, line 12) x 5.77% cost of debt (schedule D-1, page 2) x 46.21% debt ratio (schedule D-1, page 2)
(8) Adjusts for additional interest expense deduction associated with the $626 million of additional ACC rate base changes through 2010 not captured in other pro formas (see attachment DAK-2, line 13)
(9) Equals income taxes of columns e-f+g

Arizona Public Service Company
Funds From Operations (FFO) To Adjusted Debt Ratio *

	12/31/2007	12/31/2008 (a)	12/31/2009	12/31/2010 (b)
Present Rates	18.6%	23.0%	17.6%	16.6%
Proposed Rates	18.6%	23.0%	19.1%	20.8%

Notes:
* BBB Range 18.0% To 28.0%
(a) Assumes $400 million common equity issuance in 2008
(b) Assumes $300 million common equity issuance in 2010

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 1, column 2
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Palo Verde Unit 3 Steam Generator [Rate Base]**
Adjustment to Test Year rate base to include the replacement of the Palo Verde Unit 3 Steam Generator and the related Low Pressure Turbine Rotor. The equipment was placed into service on 01/19/2008.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ 49,135
2.	Less: Accumulated Depreciation and Amortization	(44,725)
3.	Net Utility Plant in Service	$ 93,860
4.	Less: Total Deductions	-
5.	Total Additions	-
6.	**Total Rate Base**	**$ 93,860**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 1
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Palo Verde Unit 3 Steam Generator [Income Statement]**
Adjustment to Test Year depreciation, interest expense and property and income taxes related to the addition to Rate Base for the Palo Verde Unit 3 Steam Generator and the related Low Pressure Turbine Rotor, as shown on Schedule B-2, page 1, column 2.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expense	-
5.	Depreciation and Amortization	1,222
6.	Other Taxes	485
7.	Total Expenses	1,707
8.	**Operating Income (before income tax)**	**$ (1,707)**
9.	Interest Expense	2,503
10.	Taxable Income	(4,210)
11.	Current Income Tax Rate - 39.36%	(1,657)
12.	**Operating Income After Tax**	**$ (50)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 1, column 3
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Cholla Generating Station Environmental Projects [Rate Base]**
Adjustment to Test Year rate base to include Cholla Generating Station Environmental Capital Projects projected to close to plant in service by May 2008. This is net of contributions received under Environmental Improvement Surcharge.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ 15,213
2.	Less: Accumulated Depreciation and Amortization	(676)
3.	Net Utility Plant in Service	$ 15,889
4.	Less: Total Deductions	-
5.	Total Additions	-
6.	**Total Rate Base**	**$ 15,889**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 2
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Cholla Generating Station Environmental Projects [Income Statement]**
Adjustment to Test Year operations, depreciation, interest expense, and property and income taxes related to the addition to Rate Base for the Cholla Generating Station Environmental Projects, as shown on Schedule B-2, page 1, column 3.

Line No.	Description	Total Company Amount
1.	**Revenues**	$ -
2.	Other Electric Revenue	
3.	**Other Operating Expenses**	-
4.	Operations Excluding Fuel Expense	341
5.	Depreciation and Amortization	91
6.	Other Taxes	432
7.	Total Expenses	
8.	**Operating Income (before income tax)**	**$ (432)**
9.	Interest Expense	424
10.	Taxable Income	(856)
11.	Current Income Tax Rate - 39.36%	(337)
12.	**Operating Income After Tax**	**$ (95)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 2, column 4
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Yucca Units 5 and 6 [Rate Base]**
Adjustment to Test Year rate base to include the cost of construction for Yucca Units 5 & 6. These units are scheduled to be placed into service during the summer of 2008.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ 77,123
2.	Less: Accumulated Depreciation and Amortization	-
3.	Net Utility Plant in Service	$ 77,123
4.	Less: Total Deductions	-
5.	Total Additions	-
6.	**Total Rate Base**	**$ 77,123**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 3
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Yucca Units 5 and 6 [Income Statement]**
Adjustment to Test Year operations, depreciation, interest expenses, and property and income taxes related to the addition to Rate Base for Yucca Units 5 and 6, as shown on Schedule B-2, page 2, column 4.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expense	206
5.	Depreciation and Amortization	2,383
6.	Other Taxes	431
7.	Total Expenses	3,020
8.	**Operating Income (before income tax)**	**$ (3,020)**
9.	Interest Expense	2,056
10.	Taxable Income	(5,076)
11.	Current Income Tax Rate - 39.36%	(1,998)
12.	**Operating Income After Tax**	**$ (1,022)**

Post Test Year Plant Additions Summary

(Thousands of Dollars)

	Projects over $1,000,000		Projects $1,000,000 to $500,000 [3]		Projects $500,000 to $10,000 [3]		Total	
	# of Projects	$ of Projects	# of Projects	$ of Projects	# of Projects	$ of Projects	# of Projects	$ of Projects
Generation [1]								
Fossil	10	$ 60,670	7	$ 5,326	102	$ 12,282	119	$ 78,278
Nuclear	7	17,785	6	4,302	37	5,240	50	27,327
Total Generation	17	78,455	13	9,628	139	17,522	169	105,605
Distribution [1]	5	12,758	15	8,724	966	49,009	986	70,491
Other [2]	16	63,005	8	5,152	22	7,005	46	75,162
Total	38	$ 154,218	36	$ 23,504	1127	$ 73,536	1201	$ 251,258

1. Generation and Distribution jobs included have an estimated cost of greater than $10,000 with an estimated in-service date prior to 10/01/2009.
2. Other jobs included have an estimated cost of greater than $200,000 with an estimated in-service date prior to 10/01/2009.
3. Project totals above are net of approximately $4.5M in Contributions in Aid of Construction (CIAC) and other miscellaneous credit reductions to CWIP balances.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 2, column 5
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Post Test Year Plant Additions [Rate Base]**
Adjustment to test year rate base to include post test year plant additions for generation, distribution and other projects with an estimated in service date prior to 10/01/2009.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ 251,258
2.	Less: Accumulated Depreciation and Amortization	-
3.	Net Utility Plant in Service	$ 251,258
4.	Less: Total Deductions	-
5.	Total Additions	-
6.	**Total Rate Base**	**$ 251,258**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 2, column 4
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Post Test Year Plant Additions [Income Statement]**
Adjustment to Test Year operations to include other interest expense, property taxes and reduced income taxes associated with post test year plant additions. Proforma adjusted as shown on Schedule B-2, page 2, column 5.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expense	-
5.	Depreciation and Amortization	14,134
6.	Other Taxes	3,214
7.	Total Expenses	17,348
8.	**Operating Income (before income tax)**	**$ (17,348)**
9.	Interest Expense	6,699
10.	Taxable Income	(24,047)
11.	Current Income Tax Rate - 39.36%	(9,465)
12.	**Operating Income After Tax**	**$ (7,883)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 2, column 5
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Attrition**
Adjustment to Test Year to include operations and rate base driven cost of capital expense growth exceeding sales growth from the Test Year through 2010, the first full year rate will be in effect. For simplicity, the adjustment is shown on one line, the operations excluding fuel expense line.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expense	79,278
5.	Depreciation and Amortization	-
6.	Other Taxes	-
7.	Total Expenses	79,278
8.	**Operating Income (before income tax)**	**$ (79,278)**
9.	Interest Expense	-
10.	Taxable Income	(79,278)
11.	Current Income Tax Rate - 39.36%	(31,204)
12.	**Operating Income After Tax**	**$ (48,074)**

Peter M. Ewen

DIRECT TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

Table of Contents

I. Introduction 1

II. Summary of Testimony 3

III. Effect of Growth on System Costs 5

IV. Base Fuel and Purchased Power Pro Forma 19

- A. Increased Sales Growth and Resource Mix 24
- B. Commodity Prices 24
- C. Coal Prices 25
- D. Generation Resource Changes 25

V. Other Adjustments to Test Year Fuel Revenue and Expense 26

VI. Pro Forma Adjustments to Normalize Maintenance 27

VII. Pro Forma Adjustments to Normalize Electricity Sales 29

VIII. Revenue Net of Fuel Projections in the Attrition Pro Forma 33

IX. Conclusion 35

Summary of Base Fuel Cost Changes ..... Attachment PME-1

Average Fuel Cost by Type of Resource ..... Attachment PME-2

Base Fuel and Purchased Power Pro Forma ..... Attachment PME-3

Components of Current and Proposed Base Fuel Rates ..... Attachment PME-4

Remove Test Year Revenue & Deferred Fuel Amortization Pro Forma ..... Attachment PME-5

Remove Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals Pro Forma ..... Attachment PME-6

Normalize Non-Nuclear Maintenance Expense Pro Forma ..... Attachment PME-7

Normalize Nuclear Maintenance Expense Pro Forma ..... Attachment PME-8

Planned Outage Days by Plant ..... Attachment PME-9
Comparison of Current Authorized EFOR to Pro Forma EFOR ..... Attachment PME-10
Normalize Weather Conditions Pro Forma ..... Attachment PME-11
Annualize Customer Levels Pro Forma ..... Attachment PME-12
Normalize Uncollected Fixed Costs Pro Forma ..... Attachment PME-13

DIRECT TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Peter M. Ewen. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY?

A. I am Manager of the Revenue and Fuel Analysis and Forecasts Department for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for preparing the Company's short-range and long-range forecasts of system peak demand and energy sales, and projecting the optimal dispatch of available resources to minimize the cost of meeting those energy requirements.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received Bachelors and Masters degrees in Economics from Arizona State University in 1985 and 1988, respectively. I have analyzed and forecasted electric energy and demand growth since 1988, first as a Staff member of the Arizona Corporation Commission ("Commission") and, since 1990, as an employee for APS. I have specifically analyzed the dispatch of our generating units in combination with market purchases to serve native load demand since 1998, and assumed full responsibility for making the optimal dispatch and associated fuel cost projections in 2000. I was formerly President of the Arizona Economic Round Table, a group of Arizona-based economists that specialize in studying the Arizona economy, and I am still a member of that organization. I

also serve on the Joint Legislative Budget Committee's Finance Advisory Committee. This advisory committee consists of a group of state economists who advise the Joint Legislative Budget Committee staff on the adequacy of the economic projections underlying their state revenue projections.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses the impact of continuing customer growth in the APS service territory on the Company's increasing capital expenditures and the system average cost of fuel for generation and purchased power. In particular, I explain why growth is a source of financial pressure for the Company today compared to prior years. I also sponsor the Company's Base Fuel and Purchased Power pro forma, which sets forth the base rate level of fuel and purchased power expenses. This requested base fuel rate reflects conditions expected to exist at the time the requested rates are likely to be in effect. My testimony explains the reasons for this increase, focusing in particular on the increases in wholesale market prices and the Company's increasing reliance on natural gas.

In addition, I sponsor the "Total Company" column for several pro forma adjustments to the Test Year set forth in SFR Schedule C-2, including:

1) Base Fuel and Purchased Power,
2) Remove Test Year PSA Revenue and Deferred Fuel Amortization,
3) Remove Test Year PSA Deferrals and Mark-to-Market Accruals,
4) Normalize Non-Nuclear Maintenance Expense,
5) Normalize Nuclear Maintenance Expense,
6) Normalize Weather Conditions,
7) Annualize Customer Levels, and
8) Normalize Uncollected Fixed Costs.

Finally, I discuss the forecasted revenue net of fuel levels included in the attrition pro forma sponsored by APS Witness Daniel Kearns.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS is the largest major utility in the second fastest growing state in the United States (next to Nevada). While the recent downturn in the residential housing market has caused the striking growth rate that Arizona experienced over the past decade to slow, growth continues nonetheless. In fact, most if not all public forecasts expect Arizona's growth rate to pick up again and continue over the long term.

Although growth is not new to APS, the capital spending that the Company must undertake to meet its increasing demand and maintain its existing system is significantly higher today than it has been historically and is placing enormous financial pressure on APS. This is true for several reasons. First, growth has largely exhausted the margin of capacity that had been available in the Company's existing system to serve new load, and APS must continue to upgrade and expand that system in order to accommodate future growth. Second, the Company's additional infrastructure needs come at a time when the cost of materials, commodities, and land used for construction is substantially higher than it had been historically—driving the cost of that infrastructure up considerably compared to prior years. Third, in addition to construction costs, APS's other non-fuel costs are increasing, reversing a previously declining unit cost trend that had historically offset the costs of growth. Historic economies of scale that once helped relieve the costs of growth have evaporated. The net result is that, today, APS's non-fuel costs are significantly higher than the

revenue that APS receives from rates and are increasing at a faster rate than the associated revenues.

Just as non-fuel costs have increased, APS's fuel costs have also risen since the twelve months ending December 31, 2007 (the "Test Year"). APS's current base fuel recovery amount of 3.2491¢ per kilowatt-hour ("kWh"), established in Decision No. 69663, was premised on expected 2007 cost levels at the time of my testimony in that case. Since then, the system average fuel cost has continued to increase because of a number of factors, including sales growth, increasing natural gas, coal, and purchased power prices, and the increasing contribution of natural gas resources to the APS generation fuel mix. Attachments PME-1, PME-2, and PME-4 show these changes and their respective impact on the Company's overall fuel costs.

Given the increase in fuel costs that has occurred since fuel rates were last set, the Company proposes that base fuel recovery be set at 3.88¢/kWh, which rate reflects normalized levels of power plant performance, expected 2010 fuel and purchased power prices, and a credit for anticipated off-system sales margins. This rate will allow the Company to recover fuel costs incurred during the Test Year, adjusted to reflect the conditions the Company expects to experience during 2010, when the rates requested in this proceeding will likely become effective. The method by which I calculated this new base fuel rate is identical to the one used by the Company and accepted by the Commission in the Company's last two rate cases.

Annual jurisdictional revenues net of fuel are projected to grow by $131 million from the twelve months ending December 31, 2007 through the year 2010 under

current rates. The majority of this increase is due to projected population growth and its attendant kWh sales growth. Even so, this growth in revenue is not adequate to cover the Company's projected capital and operating expense for that same period. For this reason, the Company has proposed an attrition pro forma that accounts for the resulting shortfall in revenues. APS Witness Kearns sponsors that pro forma adjustment, relying in part on my projections regarding the Company's revenue net of fuel.

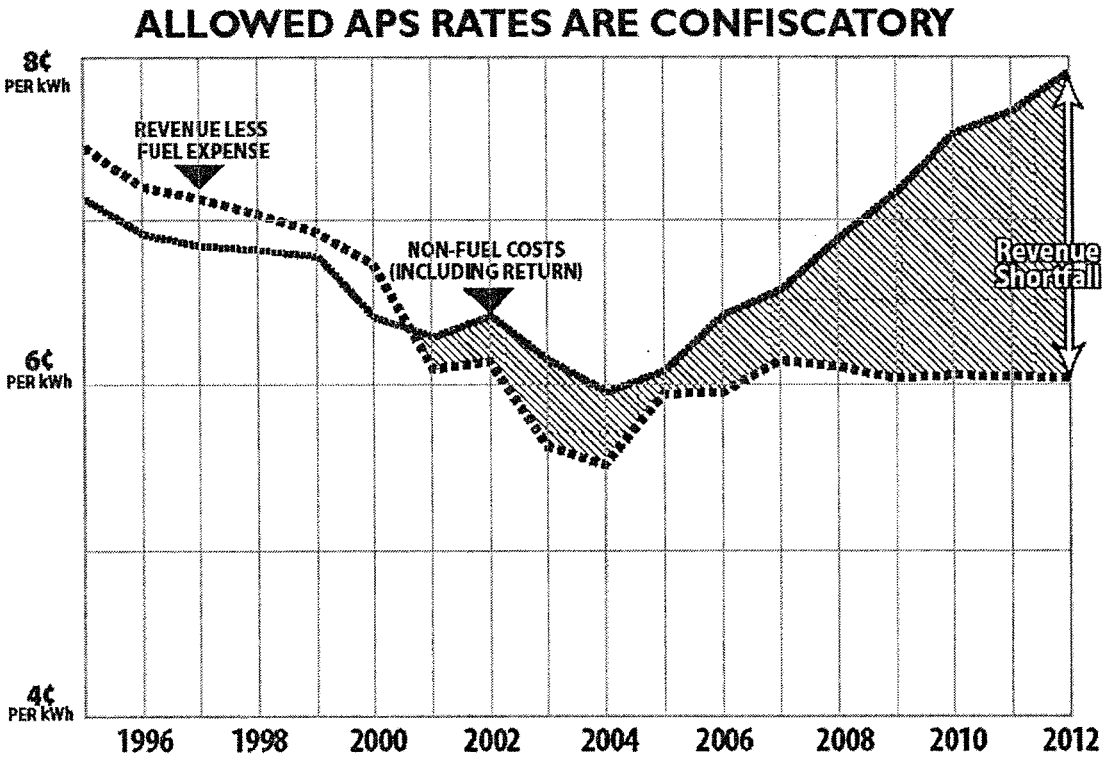
III. EFFECT OF GROWTH ON SYSTEM COSTS

Q. IN HIS DIRECT TESTIMONY, MR. BRANDT EXPLAINS THAT THE COMPANY'S GROWTH IS CAUSING APS SIGNIFICANT FINANCIAL HARDSHIP. WHAT EVIDENCE DO YOU HAVE OF THIS?

A. The clearest evidence that growth is causing APS financial difficulties is the fact that the Company's average non-fuel costs per kWh (that is, the Company's annual costs, less fuel expense, divided by annual electricity sales) are rising faster than its average non-fuel revenues per kWh. In other words, the Company's revenue growth is not keeping pace with the increase in costs that the Company has needed to and still must incur to both meet the demands of growth and maintain its existing system—a trend that leaves a gap between costs and revenues that will only widen in future years without action by the Commission. For ease of reference, I will refer to the Company's per kWh costs and per kWh revenues as "unit" costs and "unit" revenues.

The growing cost/revenue disparity is plainly shown on the following graph, which compares the Company's average unit costs to average unit revenues over the last decade and for the next five years (assuming no change in the Company's future rates from current levels). This type of comparison normalizes for sales level differences over time in order to more clearly compare

the Company's cost structure to its revenue stream.



As this graph shows, the Company's non-fuel unit costs declined steadily from 1995 to 2004, but have since turned around and are now increasing at a fairly rapid rate. At the same time, from 1995 to 2004, the Company's unit revenues (net of fuel expenses) fell more quickly than costs and, but for the very small non-fuel rate increases authorized in 2005 and 2007 (which were still insufficient to cover APS's rising costs), have shown no upward trend whatsoever. Among other things, this fact demonstrates that the additional revenue received from sales growth has not been sufficient to cover the Company's rising non-fuel costs. What's more, in the absence of any immediate rate relief, the divergence between costs and revenues will only grow at an ever-accelerating rate in the future.

Q. HAS THIS FINANCIAL PRESSURE BEEN AN ISSUE ONLY SINCE 2004?

A. No. As the graph above illustrates, unit prices fell below unit costs as early as 2001 and continued to fall through 2004 (in part because the Company reduced its rates in accordance with Decision No. 61973 (October 6, 1999)). Moreover, the historic decline the Company had seen in unit costs began to flatten out during this period, thus eliminating a source of previously existing financial relief. APS has been unsuccessfully trying to play catch-up ever since.

Q. WHAT IS THE PRIMARY REASON FOR THE COMPANY'S INCREASE IN UNIT COSTS?

A. The primary reason for the Company's increase in unit costs is the capital investment required to meet the Company's growth in customers and electricity demand while maintaining and improving its existing system. APS expects to spend ***$3 billion*** over the next 3 years on capital projects, and a significant portion of this spending will be driven by meeting the needs of growth. As these capital projects are completed, the investment is placed into plant-in-service and starts to depreciate, incur property taxes, and require a return to the debtholders and equity investors who funded the investment. APS Witnesses Donald Brandt and Daniel Kearns describe the impact of these capital investments on the Company's financial results in more detail. For present purposes, it is important to recognize that these capital costs, which are driven almost exclusively by the Company's capital spending requirements, are rising faster than the Company's sales of electricity, and that is what is putting more upward pressure on the Company's overall costs.

A simple comparison of unit costs between 2007 and 2010 shows the financial impact of the Company's required capital investment:

	2010	2007	Chg
Depreciation (¢/kWh)	1.49	1.28	16.4%
Property Taxes (¢/kWh)	0.48	0.45	6.7%
Interest/Equity Return (¢/kWh)	2.98	2.43	22.6%
Total (¢/kWh)	4.95	4.16	19.0%

As a general proposition, revenue grows with sales growth and, in the absence of rate relief, unit revenues will not change. With that understanding, what this analysis demonstrates is that the Company's costs related to capital spending are increasing 19.0% **faster** than the Company's electricity sales—and, by extension, the Company's revenue stream absent rate relief.

Q. WHY IS THE COMPANY'S PLANNED CAPITAL INVESTMENT SO HIGH OVER THE NEXT SEVERAL YEARS?

A. APS is required to spend upwards of one billion dollars per year over the next several years both to meet its continuing growth in customer and electricity demand and to maintain its existing system, and the costs of meeting those obligations have risen considerably in recent years. Mr. Brandt provides a summary of the specific capital projects the Company is working on or planning to work on in the near future and explains the impact that inflation in key commodities and materials costs has had on the Company's capital investment requirement.

Q. PLEASE DESCRIBE THE RAPID GROWTH IN APS'S SERVICE TERRITORY.

A. APS's growth environment is unlike that of most other electric utilities in the country. APS is the largest electric utility in Arizona, serving almost half of the state's population. Not surprisingly, given Arizona's growth rate, APS has been one of the fastest growing utilities in the United States, with annual customer growth increasing at a rate of 3 to 4% for more than the past ten years.

Indeed, for over a decade, APS experienced a steady increase in not just customers, but in energy and peak demand growth. From 1995 to 2000, for example, APS placed in service roughly 175,000 initial meter sets and increased its cumulative electricity sales by over 14 million kWh. (An initial meter set, also called a "new" meter set, is recorded the first time a new residence or business has an electric meter activated on the property and is one of the best measures the Company has of new construction activity in its service territory.) From 2000-2005, APS added approximately 200,000 new meter sets and increased its cumulative kWh sales by more than 6.2 million. Although growth has slowed considerably since 2005, APS estimates that it will add at least another 125,000 new meter sets and make another 8.4 million cumulative kWh sales from 2007 to 2012. In fact, as will be discussed later in my testimony, between the Test Year and 2010, sales are expected to increase by 3.2% (even before accounting for the abnormally hot weather existing in the Test Year).

The increase in the Company's annual system peak during the same timeframe reflects these trends as well. This is important because the Company has to have enough electricity generating and delivery resources in place to meet its system peak demand each year, and significant capital investment is required to expand these system resources. From 1995 to 2007, the Company's annual peak demand increased from 4,420 megawatts ("MW") to 7,545 MW, a growth of over 70% or 4.6% per year. (The results are similar even when the effects of abnormal weather are removed from each year.) On a going forward basis, the Company expects to add approximately 800 MW by 2012, also requiring significant investment in capital resources.

The principal source of the Company's growth in electricity demand is

population and household growth in the Company's service territory. As the Commission knows, Arizona's population has been one of the five fastest growing in the United States in each decade of the past 70 years. *See* U.S. Census Bureau, Statistical Abstract of the United States: 1951 (Table 38), 1991 (Table 26), and 2008 (Table 13). According to data from the Arizona Department of Economic Security and the U.S. Census Bureau, the population growth rate in Arizona ranked second in the nation in 2007, jumping by 23% since the 2000 population census, compared to a national cumulative growth average of just over 7% during the same period. Since 2000, more than 1.1 million people have moved to Arizona, an average of more than 150,000 people annually. Two-thirds of these new residents settled in Maricopa County—APS's primary service territory.

Q. WHAT IMPACT HAS THE RECENT DOWNTURN IN THE ECONOMY HAD ON THE COMPANY'S CUSTOMER GROWTH RATE?

A. While recent economic events—most notably the downturn in the housing market—have caused Arizona's population growth to slow markedly in recent months, there is no evidence that the growth rate will decelerate to any significant degree in the long term. Arizona's recent pace of growth has been slowing with each passing month, and the current economic outlook is best described as "fluid." For that reason, the weakness in the housing and financial markets has the potential to drive Arizona's and APS's growth rate lower than that assumed in this Application. If this were to occur, however, it is likely to be only a short-lived experience. Arizona has gone through five recessions since the mid-1970s, and each has been concurrent with an economic recession at the national level. Arizona's growth rebounded after each one because the fundamental drivers of growth remained for the State. At present, there is no

indication that these fundamentals have been seriously disrupted as a result of the current economic situation. Moreover, even if new customer growth slows in the near term, the Company's capital investment will not decline proportionately for the reasons explained by APS Witnesses Brandt and Kearns in their respective testimony.

Q. WHY ARE THE COSTS OF MEETING GROWTH HIGHER FOR THE COMPANY THAN THEY HAVE BEEN HISTORICALLY?

A. The cost of growth is significantly more expensive today than it has been historically for three principal reasons. First, whatever economies of scale the Company may have been able to achieve in the past have now largely been exhausted. The amount of physical plant and equipment that APS must put in place to serve growth today—particularly for the delivery part of the business—is larger than what was required for the same purpose five or ten years ago. Second, the costs of these additional resources have gone up substantially as the prices of their component materials have increased. Third, the Company benefited from several cost-reduction trends in the past, which helped to offset rising capital costs in a material way—and those cost reductions are not repeating themselves today.

Q. WHY HAVE APS'S SYSTEM EXPANSION NEEDS INCREASED COMPARED TO WHAT THEY WERE IN PRIOR YEARS?

A. Over the past decade and a half, APS was able to meet much of its growing demand with the Company's existing generation, transmission, and distribution system through a combination of infill opportunities and increased use of its existing system. But growth has now largely exhausted the capacity remaining in that system, requiring the Company to invest substantial capital dollars to

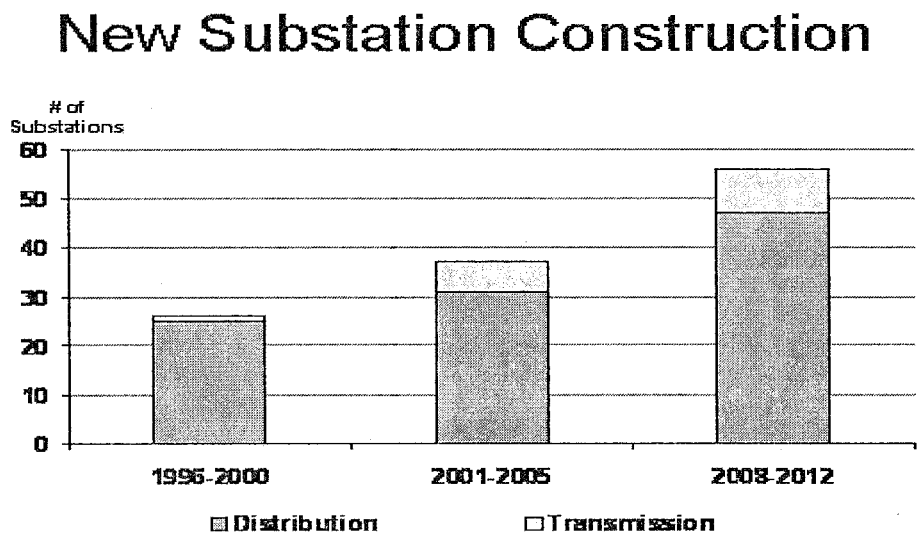
upgrade and expand its system—levels of spending that vastly exceed what the Company was required to make in the past.

On the distribution side, APS's required capital investment is substantial compared to what it was in prior years, and the Company will be required to spend almost $650 million from 2008 to 2010 on distribution projects to meet the Company's duty to serve its current and growing customer base—a number that accounts for the Commission's recent changes to APS's line extension policy. *See* Attachment DEB-3 to Mr. Brandt's Direct Testimony. The Company's capital intensity has increased from what it was historically in this regard in large part because of its diminishing ability to serve new load growth with its existing distribution facilities. In the late 1990s, APS maximized the use of its existing distribution system (which had at that time a margin of capacity available to serve new customers) to meet its growing demand. However, growth has now generally exhausted the margin of capacity previously available in its existing distribution system, so APS's construction needs—and thus its distribution investment requirements—have risen considerably. The same holds true for APS's transmission investment needs.

A simple comparison of the number of new substations added in each of three historical periods illustrates this trend in the Company's required construction. For example, from 1996 to 2000, APS added one new transmission substation and 25 new distribution substations to serve its increasing load. From 2000 to 2005, APS added 5 new transmission substations (excluding those required specifically for new generation facilities) and 31 new distribution substations. Expressed as a rate relative to the amount of new meter sets to remove any differences due to varying levels of growth during these two periods, it is clear

that the number of substation additions—and thus construction costs—required to serve growth increased considerably from one period to the next. In that vein, the Company added 0.6 new transmission substations for each 100,000 new meters installed in the 1996 to 2000 period, followed by 2.6 new transmission substations for the same number of meter installations in the 2001 to 2005 period. The story is similar for distribution substations: from 14.4 substation additions per 100,000 new meters in 1996 to 2000 up to 16.0 new substations in 2001 to 2005. Combined, these substation additions reflect a 24% increase between 1996 and 2005 in this measure of the Company's capital intensity.

All indicators suggest that this trend will continue into at least the near future. From 2008 to 2012, APS expects to add approximately 4 transmission substations and roughly 23 distribution substations to serve the same 100,000 units of growth in meter installations—a 45% increase in physical plant over what was required in the first five years of this decade and an 80% increase over what was required ten years ago. The following graph summarizes this trend.



The increase in capital intensity demonstrated by these substation additions is similarly exhibited in other elements of the system. For example, the amount of wire required for transmission system expansion has increased from approximately 175 miles per 100,000 new meter installations in the 1996-2000 period to almost 270 miles planned in the 2008-2012 period, more than a 50% increase. Substation upgrades have also been significantly more intensive recently compared to what they were in the late 1990s. Existing transmission substations were upgraded at the rate of roughly 2.8 megavolt amperes ("MVA") per 1,000 meter installations in the late 1990s and distribution substations required an additional 3.9 MVA per 1,000 meters in the same time period. By the 2000-2005 timeframe, the transmission upgrades **more than doubled** to over 7 MVA per 1,000 new meters, and distribution upgrades **increased by almost 70%** to 6.5 MVA for every 1,000 new meters. The trends in these metrics will continue to increase into the future as the now-existing system will need to be enhanced to support the additional load placed on it by the growth in new and larger customers.

On the generation side, capital spending for new generation facilities is, by its nature, considerable in amount but relatively sporadic in need, and the conclusion of the APS nuclear construction program in the late 1980s allowed this facet of the Company's electric system to require less significant investment in the decade that followed. The addition of Palo Verde provided the Company with sufficient generating capability to meet most of its load growth through the 1990s, leaving only a combination of incremental short and long-term peaking capacity purchase needs. Furthermore, the move toward a de-regulated generation market in the mid- to late-1990s heightened the uncertainty of how the Company should invest in new generation facilities in the changing regulatory environment. For these reasons, the Company did not make another sizeable investment in new generation until plants producing 1700 megawatts ("MW") of gas-fired generation were built in 2002 and 2003 by Pinnacle West Energy Corporation ("PWEC") and acquired by APS in 2005.

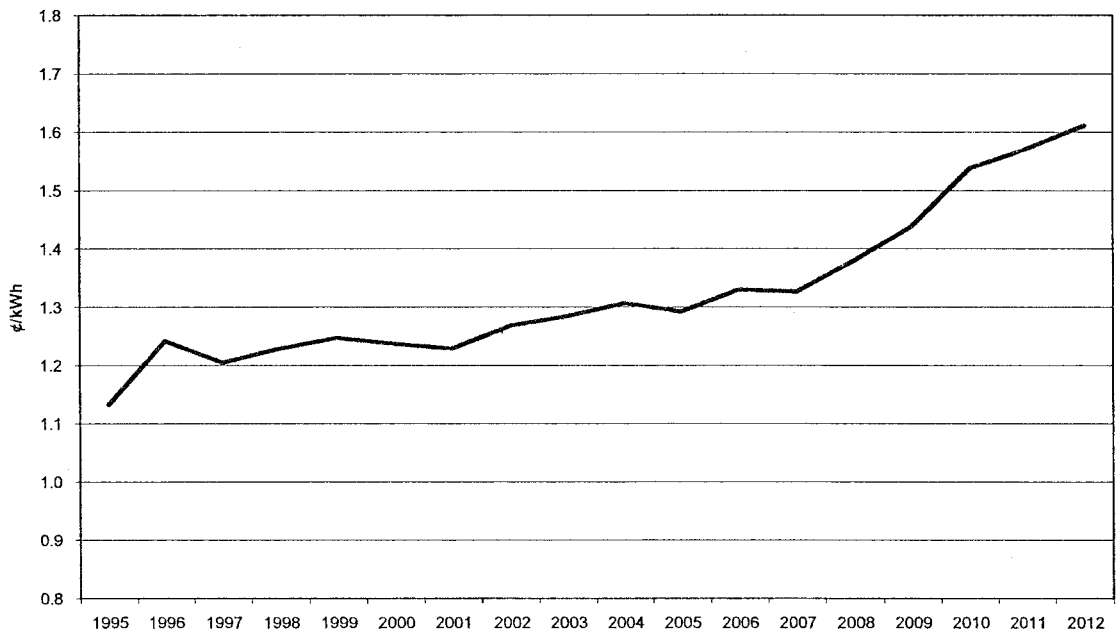
APS's generation needs today continue to increase with the Company's growing demand, and APS expects that its resource requirements will surpass its total existing resources within the next few years (a topic discussed in the Resource Alternatives Report that APS filed with the Commission in Docket No. E-01345A-08-0010). In the short run, the Company will meet a vast majority of its growing resource needs by purchasing conventional and renewable resources from the market or by encouraging the reduction in energy needs through customer use of DSM and demand response programming and distributed generation. Even so, APS will still be required to spend **more than one billion dollars** between 2008 and 2010 on power plant projects at the Company's existing production facilities. *See* Attachment DEB-3, attached to Mr. Brandt's

Direct Testimony.

Q. WHAT OTHER EVIDENCE DEMONSTRATES THAT APS'S CAPITAL INTENSITY IS INCREASING?

A. In addition to APS's physical infrastructure additions, the steady increase in the Company's capital intensity during these time periods is evidenced by a consistently rising unit cost of depreciation. As the following graph demonstrates, APS's depreciation costs have continually increased since 1995, and are now growing at a significantly faster pace than they have historically.

APS Depreciation Costs
(Excludes Regulatory Asset Amortization)



The fact that depreciation is on the rise indicates that the Company's investment in new plant and equipment, net of retirements of plant, is increasing faster than its sales growth and, hence, its revenue growth absent price changes. Rising depreciation unit costs have been a consistent feature of the Company's financial picture for at least the last ten years.

Q. HAS ANYTHING ELSE CONTRIBUTED TO THE INCREASE IN APS'S REQUIRED CONSTRUCTION EXPENDITURES?

A. Yes. As Mr. Brandt describes in detail, the Company's rising construction needs come at a time when the cost of materials, commodities, and land used for construction is significantly higher than it has been in the recent past. This increase significantly exacerbates the capital spending already required because of APS's need to expand and upgrade its system to accommodate its electricity demand.

Q. YOU MENTIONED ANOTHER FACTOR THAT HAS MADE THE COST OF GROWTH MORE CHALLENGING TODAY THAN IT HAS BEEN HISTORICALLY: THE REVERSAL OF A UNIT COST TREND. PLEASE EXPLAIN.

A. While the increase in APS's capital intensity described above has put pressure on the Company's financial condition for more than the last decade, a declining unit cost environment in the late 1990s more than offset that pressure and masked the impact of the Company's continuing capital investment needs. As the graph that compares the Company's unit costs to unit prices on page 6 shows, the declining unit cost trend that APS experienced in the last decade has since reversed, eliminating a previous and significant source of relief from the Company's increasing costs of growth.

As that graph demonstrates, APS's per unit non-fuel prices and costs actually declined on average from 1995 to 2000, but prices generally remained above costs. The average decline in costs occurred for a number of reasons. First, because of aggressive cost management and operational re-engineering, APS was able to reduce its labor force at the same time that it added almost 200,000 new customers. During the same period, national interest rates declined, and APS repeatedly took advantage of refinancing options that allowed it to reduce

its overall debt levels and lower the costs of remaining debt. Although labor benefit costs increased slightly, that increase was slow relative to APS's customer growth rate because of stock market-driven gains on the Company's pension fund assets. Further reductions to per-unit costs occurred as a result of cuts in property tax rates in the late 1990s.

As an offset to these reductions, as part of the 1999 Rate Settlement, APS received authority from the Commission to accelerate recovery of a billion dollars in regulatory assets during this period, which limited the impact of these other non-fuel cost decreases. Depreciation costs also rose because of the increase in plant needed to serve growth during this period, as previously described. The net effect was that APS's non-fuel costs per kWh (with the regulatory asset amortization) declined from 1995-2000, and APS was able to remain financially healthy while providing the price decreases to its customers required by Decision No. 61973. These historic reductions in unit costs more than offset the steady increase in the Company's capital intensity described previously.

From 2000 to 2005, the financial health of the Company began to deteriorate and at an ever-increasing pace. In part, this was driven by rapidly rising fuel costs, which were ultimately addressed in Decision No. 69663. During this period, as the Company's capital intensity continued upwards and the regulatory asset amortization period expired, APS's O&M costs, relating primarily to increasing pension fund expenses and increasing employment levels, began to grow faster than its sales. Depreciation costs also rose as even more plant was added to meet the Company's growing demand. Unit costs for property taxes and interest expense flattened out during this period, thereby eliminating a

previous source of relief for APS's non-fuel cost pressures. At the same time, the Company continued to provide the rate decreases agreed to in the 1999 Settlement through 2003.

Since that time, however, the historically beneficial unit cost trend that once offset the effect of rising depreciation costs and capital intensity has reversed, and APS is experiencing the financial impact of the cumulative increase in its non-fuel costs. Depreciation costs continue to rise, but now at an even more accelerated pace commensurate with the Company's escalating need for system infrastructure, described above. These rising costs are no longer offset by the once favorable declining cost trends relating to O&M, taxes and interest rates. Rather, O&M costs (which do not include return requirements or depreciation expenses) are expected to remain relatively flat on a per-unit basis (setting aside the cost increases which are to be specifically recovered through the DSM Adjustor Clause and the Renewable Energy Standard Tariff), and the increased pace of new investment will also lead to increased interest and equity financing costs (also on a per-unit basis).

The result is that APS's non-fuel costs are now rising and will continue to rise faster than its sales growth. As Mr. Brandt also explains, the fact that APS's rise in non-fuel costs will outpace its projected sales demonstrates that APS has generally exhausted any economies of scale that historically allowed it to offset the costs of growth.

IV. BASE FUEL AND PURCHASED POWER PRO FORMA

Q. ARE YOU PROPOSING TO ADJUST THE COMPANY'S AUTHORIZED BASE FUEL RATE?

A. Yes, I am proposing to increase the base fuel rate from 3.25¢/kWh (authorized

by the Commission in Decision No. 69663) to 3.88¢/kWh. This adjustment moves approximately $170 million out of future Power Supply Adjustor ("PSA") recovery and into base rates (at Test Year sales levels). But for the 90/10 sharing arrangement in the PSA, this would amount to no difference in the revenues actually collected from customers. With that sharing arrangement, the impact of the increase in the base fuel rate amounts to $14 million of a net increase in revenues, or less than half of one percent. Even so, it is important to update the Company's base rates both so that the attendant impact on class rate design can be accounted for and to avoid the 90/10 sharing becoming, in essence, an automatic 10% penalty. Attachment PME-1 shows the results of the proposed adjustments on Test Year revenues.

Q. WHAT FACTORS ARE BEHIND YOUR PROPOSED ADJUSTMENT?

A. Many of the same factors that have been features of the Company's previous fuel-related increases are present today. Most importantly, the increased load growth I have discussed above is being met primarily with higher cost natural gas resources or market purchases that are tied to natural gas resources. As a result, the share of the Company's total generation supply being served by low-cost coal and nuclear resources is declining. Additionally, natural gas prices in future years are higher than they were when the Company's base fuel rate of 3.25¢/kWh was set, even after accounting for the effects of the Company's natural gas and purchased power hedge plan. A quantification of these factors can be seen in Attachment PME-1. Attachment PME-2 shows the average fuel cost for the Company's major resource types embedded in the current authorized and proposed base fuel rates.

Besides these specific items, there are several important adjustments to

incorporate into the Company's base fuel rate going forward. The proposed adjustments recognize known and measurable changes to Test Year conditions and are more representative of conditions that will be present when the Company's new rates are likely to take effect. Specifically, I am proposing to normalize Test Year fuel expenses and off-system margins for:

(1) increased electricity sales due to continued growth;

(2) higher commodity market prices for natural gas and power;

(3) higher coal prices due to standard contract escalators;

(4) increased production from Palo Verde Unit 3 as a result of the steam generator replacement in December 2007;

(5) normalized maintenance and unplanned outage times;

(6) the cancellation by Salt River Project ("SRP") of a capacity power contract with APS;

(7) additional renewable resources consistent with the Company's Renewable Energy Standard ("RES") requirements; and

(8) other miscellaneous items, such as broker fees, third-party wheeling expenses, and short-term and long-term capacity costs.

Of the total proposed adjustment, $54 million reflects costs that are already reflected in the Test Year and the remaining $130 million is for costs that are normalized to 2010 levels, the time when rates from this request are likely to take effect. For the Test Year ending December 31, 2007, the Company's actual average base fuel and purchased power expense, excluding the impact of the

period's non-cash fuel cost deferrals, was 3.43¢/kWh.[1]

Q. PLEASE EXPLAIN HOW THE PRO FORMAS FOR FUEL EXPENSE AND OFF-SYSTEM MARGIN ARE DEVELOPED.

A. I developed the pro forma for fuel expense net of off-system margin using the identical approach used by the Company and accepted by the Commission for establishing the Company's base fuel rate in the last two rate cases. Under that approach, I simulated the impacts of the adjustments I mentioned above using the Company's production cost simulation tool RTSim. This computer model replicates the dispatch of the APS system and is the primary fuel expense and off-system sales forecasting tool APS uses to prepare its annual budgets, long-range fuel forecasts, and near-term operational plans. The vast majority of the input assumptions I have used in the proposed base fuel adjustment are the same as or consistent with the expected levels in the Company's operating plans prepared for internal use. Most importantly, the estimated fuel expense is based on the March 31, 2008 forward curve for natural gas and power prices and the corresponding valuation of the Company's hedges.

Q. HOW DOES THE PRODUCTION COST SIMULATION MODEL CALCULATE THE AVERAGE FUEL AND PURCHASED POWER COST?

A. The model simulates the dispatch of the APS generating units on a daily and hourly basis. It takes into account the APS system load shape, fuel prices (including wholesale market prices for power) and characteristics of APS-owned generating plants (such as heat rates, overhaul cycles, unplanned outage rates,

---

[1] Throughout the remainder of my testimony, the term "fuel expenses" may be used generically to refer to fuel and purchased power expenses.

start-up costs and ramp rates, among others), along with commitments for purchases and sales of power. The model also simulates necessary market purchases for those times when load exceeds generating capacity, and likewise simulates market sales during those times when the system is not fully utilized but generating units are economic.

The projected hourly dispatch of each of the units, along with wholesale market purchases and sales, are priced out at the corresponding contract or market price projections included in the model. Fixed costs—those expenses that do not vary directly with the level of production—are then added to the model results. These expenses include firm gas transportation, fuel handling, third party wheeling costs, wholesale market capacity costs, and broker fees. The result is the total expected fuel expense and off-system sales revenue consistent with the assumptions used in the model.

Q. DO THESE RESULTS FLOW DIRECTLY INTO YOUR PROPOSED FUEL PRO FORMA?

A. No. The process I have used captures the impacts of the relevant factors on the Company's *average* base fuel cost. The change in the average cost from the Company's Test Year amounts applied to the adjusted Test Year retail sales amounts produces the appropriate adjustment for the Test Year pro forma. This calculation is shown on Attachment PME-3. Attachment PME-4 shows the major components of the proposed base fuel rate of 3.88¢/kWh and the current authorized level of 3.25¢/kWh. This base fuel rate results in a pro forma to Test Year fuel and purchased power costs of $129,649,000 (see SFR Schedule C-2, page 2, column 6).

A. Increased Sales Growth and Resource Mix

Q. HOW IS GROWTH AFFECTING SYSTEM FUEL COSTS?

A. As discussed at length above, APS has one of the fastest growing service territories in the country and growth is one of the dominant factors producing increased fuel and purchased power expenses. The Company's incremental sales attributable to growth must be met primarily with high-cost natural gas and purchased power. That incremental sales growth, therefore, is leading to a shift in the Company's fuel mix to a heavier emphasis on natural gas resources. Attachment PME-2 shows the import of this shift by comparing fuel costs by resource in the Company's current authorized base fuel cost and the pro forma adjustment I am proposing. Each percentage point increase in the share of total energy supplied by natural gas and purchased power raises the Company's fuel costs by approximately $15 million at Test Year sales levels.

B. Commodity Prices

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO TEST YEAR FUEL EXPENSE FOR FUEL PRICE CHANGES?

A. Yes. Commodity prices for natural gas and wholesale market power have increased from the levels included in the current base fuel rate and translate into an increase in fuel expense of $46.1 million net of the value of the Company's hedge contracts. At the close of the market on March 31, 2008, delivered natural gas prices for calendar year 2010 averaged $8.77/MMBTU. These prices represent a 19% increase over the delivered prices the Company is currently recovering in base rates.

In addition, because natural gas is the marginal fuel source for most wholesale power transactions, power prices have risen in concert with gas prices. Prices

for on-peak power delivered at Palo Verde for calendar year 2010 averaged almost $80/MWh on March 31, 2008, and the weighted average of the on-peak and off-peak 2010 power prices the Company expects to pay is $58/MWh.

C. Coal Prices

Q. ARE YOU PROPOSING ANY ADJUSTMENTS FOR FUEL PRICES OTHER THAN NATURAL GAS AND POWER?

A. Yes. Coal prices have continued to be pressured by inflationary factors that are elements of the Company's long-term coal contracts. Price indices for diesel fuel, steel, labor, and benefits costs have all increased at significant rates and these are some of the critical components in the Company's coal contracts. Because of these changes, coal costs are expected to average $19.15/MWh in 2010 compared to an average cost of $17.11/MWh in current rates. This is a 12% increase in average costs and translates into a $28.5 million increase in fuel expense for the almost 13,000 GWh of coal production expected in 2010.

D. Generation Resource Changes

Q. ARE ANY RESOURCE CHANGES EXPECTED TO IMPACT FUEL COSTS?

A. Yes. The Company's Territorial and Contingent ("T&C") Agreement with SRP provides firm capacity, non-firm capacity, and associated energy that is indexed to the price of gas. A provision of the T&C Agreement allows SRP to cancel any or all of the capacity with three years notice. SRP has notified the Company that this agreement will be canceled effective June 15, 2010. Because that resource will no longer be available to APS, it would be inappropriate to include its impacts in the Company's base rates extending beyond 2009. Therefore, I have eliminated that resource from the fuel calculations for 2010 and also excluded the associated capacity payments.

This resource loss is partially offset by the availability of 96 MW from Yucca Units 5 and 6, which are scheduled to become operational in the Summer of 2008. Additionally, the just-completed steam generator replacement project at Palo Verde Unit 3 increased the capacity available to the system from that low-cost resource by 20 MW. The Company is also continuing to acquire energy from renewable resources in line with its commitments to meet the requirements of the RES. I have included each of these effects in my adjustments, as well.

Finally, the planned and unplanned outage time for each of the Company's generating resources has been normalized in a manner consistent with the normalization of maintenance expense for these plants. This normalization affects the availability of the various resources in the pro forma adjustment simulation. I describe the method of normalization in more detail in the Maintenance Normalization section below. Changes in outage time from the levels included in current rates are minor.

V. OTHER ADJUSTMENTS TO TEST YEAR FUEL REVENUE AND EXPENSE

Q. DURING THE TEST YEAR, THE COMPANY RECOVERED PRIOR PERIOD FUEL COSTS THROUGH THE PSA. HAVE YOU REMOVED THESE REVENUES?

A. Yes. Attachment PME-5 is a pro forma that removes revenues related to prior period fuel expense collected through the PSA from the Test Year. In addition, it removes related prior period amortization of deferred fuel. Together, the pre-tax revenue impact on the Test Year is an increase of slightly more than $13 million. This adjustment essentially accounts for the write-off of replacement power costs for certain Palo Verde outages in 2005 that were disallowed by the Commission in Decision No. 69663 and prevents those costs from being

included in base rates going forward. This pro forma is included in SFR Schedule C-2 on page 3, column 7.

Q. WHAT OTHER CHANGES TO TEST YEAR FUEL EXPENSE ARE YOU PROPOSING?

A. In addition to the changes described above, I have included a pro forma that removes the PSA fuel deferrals and deferred non-cash mark-to-market accounting entries from Test Year expense. These non-cash accounting adjustments have no bearing on the Company's anticipated fuel expenses in 2010 and beyond. The combined pre-tax impact of these adjustments is approximately $189 million as shown on Attachment PME-6 and in SFR Schedule C-2, page 3, column 8.

VI. PRO FORMA ADJUSTMENTS TO NORMALIZE MAINTENANCE

Q. HAVE YOU MADE AN ADJUSTMENT TO NORMALIZE MAINTENANCE?

A. Yes, I am proposing to adjust both planned maintenance time and unplanned outage time to be consistent with an average year. This adjustment is necessary because outage time at each of the power plants in the Test Year for planned routine maintenance and unplanned forced outages is not indicative of the normal levels of availability. These adjustments have an impact on the Company's fuel expense, as well as operations and maintenance ("O&M") expense. I have adjusted Test Year O&M expenses to normalize maintenance levels for the Company's production plant in service at December 31, 2007. This has been done separately for the Company's nuclear facilities and its non-nuclear facilities. Using this methodology, the non-nuclear generation maintenance pre-tax operating income adjustment is $(3.3) million and the nuclear generation maintenance pre-tax operating income adjustment is $5.6

million. The O&M expense adjustments shown in Attachments PME-7 and PME-8 include the impacts of the outage time normalization for all of the units. These pro forma adjustments are included in SFR Schedule C-2 on pages 3 and 4, columns 9 and 10.

Q. HOW DID YOU ADJUST THE OUTAGE TIME TO NORMALIZE THE TEST YEAR RESULTS?

A. I used two separate approaches for normalizing outage time. Planned maintenance for each generating plant is an average over the routine overhaul cycle for the plant type. For example, the Company's coal plants are on a six-year overhaul cycle, which means that each of the coal units should experience a major overhaul once in every six-year period. The nuclear units are on an 18-month refueling cycle. Any single year, such as the Test Year, does not represent the average maintenance time and expense levels that can reasonably be expected when rates established in this case will be in effect. Attachment PME-9 shows the resulting number of planned outage days by plant and the required adjustments in the RTSim model to the planned maintenance schedule from the Company's 2007 LRF.

Unplanned outage time is based on the Company's forecast of future plant performance included in the Company's 2007 LRF. These levels are determined by reviewing historical performance and adjusting for corrective measures expected to be put in place in future maintenance outages. Attachment PME-10 shows the comparison of normalized outage time, expressed as an effective forced outage rate ("EFOR"), to the normalized outage rate levels included in the current Base Fuel Rates. From the Attachment, one can see that the EFOR levels the Company is proposing are quite similar to those in current rates.

Q. HOW DID YOU ADJUST THE MAINTENANCE EXPENSES TO NORMALIZE THE TEST YEAR RESULTS?

A. The maintenance expenses were normalized in a similar fashion to the outage time. For non-nuclear generating units, normal maintenance levels are determined by averaging the maintenance expense at each power plant using the six-year average maintenance cycle. Normal Palo Verde expenses are based on historical expenses for a three-year period. Labor costs, including overtime costs, have been adjusted to reflect historical labor cost increases. Non-labor maintenance costs were adjusted to current costs levels using the Handy-Whitman cost indices.

VII. PRO FORMA ADJUSTMENTS TO NORMALIZE ELECTRICITY SALES

Q. WHAT IS THE COMPANY'S PROPOSED PRO FORMA ADJUSTMENT TO NORMALIZE TEST YEAR WEATHER CONDITIONS?

A. Attachment PME-11 shows a reduction to Test Year revenues of $39.4 million and to Test Year operations expenses of $17.4 million that would have occurred if normal weather conditions had been experienced during the Test Year. Electricity sales to residential, commercial and industrial customers were higher by about 445,000 MWh than they otherwise would have been. This pro forma is included in SFR Schedule C-2 on page 4, column 11.

Q. HOW WAS THE SALES IMPACT OF NORMAL WEATHER CALCULATED?

A. The method used for normalizing the sales effects from abnormal weather conditions is the same methodology as has been accepted previously by the Commission. The calculation of weather-normalized sales applies the difference between actual weather conditions and normal weather conditions to a customer class-specific factor that tracks the sensitivity of average customer monthly

usage to changes in weather conditions. Summer weather conditions are defined as the product of the number of cooling degree-days ("CDD") in the month and the natural log of average humidity for the month. Winter weather conditions are defined as the number of heating degree-days ("HDD") in the month. The weather-sensitivity factor is calculated from a set of statistical models, which track the systematic correlation between average customer usage and weather over time for the residential and small, medium and large general service classes. As one would expect, the correlation between average monthly usage and weather indices is very strong.

Q. HOW WAS NORMAL WEATHER DETERMINED?

A. The CDD and HDD data are based on temperature readings from the National Weather Service at Phoenix Sky Harbor International Airport. The humidity data used in the construction of the summer weather index also relates to Sky Harbor. Normal weather is computed for each month as the most recent 10-year average ending December 31, 2007. For example, normal weather for July is the average of actual weather in each July from 1998 through 2007.

Q. HOW WERE THE REVENUE ADJUSTMENTS IN THE WEATHER NORMALIZATION PRO FORMA ADJUSTMENT DETERMINED?

A. The difference between actual sales and weather normalized sales is multiplied by the December 31, 2007 rate levels, which reflects the rates authorized in Decision No. 69663. This calculation was made on a month-by-month basis for each class of customer.

Q. ARE CORRESPONDING EXPENSES NORMALIZED?

A. Yes. Test Year expenses directly affected by kWh consumption are normalized by multiplying the weather normalized kWh consumption by the Test Year

average fuel expense and the Open Access Transmission Tariff ("OATT") rate embedded in base rates during the Test Year.

Q. ARE FUEL AND OATT EXPENSES THE ONLY EXPENSES THAT VARY SYSTEMATICALLY WITH ELECTRICITY SALES LEVELS?

A. Yes, which is why these are the only expenses that require adjustments corresponding to the revenue adjustments.

Q. ARE YOU ALSO PROPOSING A SALES-RELATED PRO FORMA ADJUSTMENT TO ANNUALIZE CUSTOMER COUNTS?

A. Yes. Attachment PME-12 shows the increase in Test Year revenues and expenses for this pro forma, which nets to a pre-tax operating income adjustment of $22.5 million (see SFR Schedule C-2, page 4, column 12). During the Test Year, APS added customers throughout the year such that the number of customers receiving service at December 31, 2007 was greater than the number of customers in every previous month. Because the Company believes these customers are here to stay, the Company annualizes the Test Year's customer levels by assuming that the December level of customers had been present for the full year. This adjustment is consistent with previous Commission decisions adopting pro forma adjustments for year-end customer levels.

Q. HOW WAS THE ANNUAL NUMBER OF CUSTOMERS DETERMINED?

A. The customer annualization pro forma adjusts the number of customers each month to be consistent with the number of customers at the end of the Test Year, while preserving the natural seasonality inherent in customer levels. The "ratio of customer change" is the mechanism by which this is accomplished. These ratios use the midpoint of each month as a cut-off point for determining if

customers have been billed in a month. The Company counts active accounts as customers only if they have been billed for more than half of the month. Therefore, customers added during the first half of the month are assumed to have been billed for consumption during the entire month, while customers added during the second half of the month are assumed to have been billed for zero consumption for that month. Accordingly, for December 2007, customers added during the second half of the month have not been billed for 1/24th of the Test Year. Customers added after the midpoint of November 2007 represent 3/24th of the annual increase in customers who would have been billed for November if they had been customers at the start of November. Likewise, 5/24th for customers added after the midpoint of October 2007, 7/24th for customers added after the midpoint of September 2007, and so forth. These customer additions are then added to the actual customer counts for each month to arrive at the adjusted annualized counts.

Q. HOW WERE SALES AND REVENUE LEVELS THAT CORRESPOND WITH THESE CUSTOMER LEVELS DETERMINED?

A. The monthly adjustments to customer counts are multiplied by the corresponding monthly weather normalized kWh usage for residential and small, medium and large general service classes, or the actual monthly usage for the other classes, which are not weather normalized. The resulting kWh adjustment is then applied to the rate levels authorized in Decision No. 69663. This calculation was made on a month-by-month basis for each class of customer.

Q. ARE THERE CORRESPONDING EXPENSES THAT NEED TO BE ADJUSTED?

A. Yes. As is done in the weather normalization pro forma adjustment, Test Year expenses are then normalized by applying the kWh adjustment to the Test Year

average fuel expense and OATT rate embedded in base rates during the Test Year.

Q. WHAT OTHER SALES-RELATED REVENUES OR EXPENSES ARE YOU PROPOSING TO ADJUST?

A. The specific spending level for DSM programs set in Decision No. 69663 requires an adjustment to both usage and revenue in the Test Year. The Company will experience a loss in revenue due to a reduction in customer usage as these programs are implemented and become successful. The expected usage reduction from the implementation of programs in 2010 will be approximately 220,696 MWh. The resulting revenue loss is calculated by multiplying the Test Year revenue in cents/kWh, less the Test Year fuel cost in cents/kWh, by these expected MWh reductions. The pre-tax operating revenue adjustment of $15.7 million resulting from these sales adjustments is set forth in the Uncollected Fixed Cost pro forma and is included as Attachment PME-13 and is in SFR Schedule C-2 on page 5, column 13. The base fuel rate of 3.88¢/kWh, which I proposed earlier in my testimony, includes the benefit of avoiding 220,696 MWh of combined generation and purchased power due to these approved DSM programs. If this DSM adjustment were to be rejected, the base fuel rate of 3.88¢/kWh would have to be increased.

VIII. REVENUE NET OF FUEL PROJECTIONS IN THE ATTRITION PRO FORMA

Q. WHAT IS THE COMPANY'S PROJECTED REVENUE NET OF FUEL GROWTH AS SHOWN IN THE ATTRITION PRO FORMA?

A. ACC-jurisdictional electric operating revenues net of fuel expenses for the calendar year 2010 under current rate levels are projected to be $1.76 billion. Excluding $58 million of revenue increases (net of fuel expenses) related to the

RES Tariff and DSM Adjustor Clause which are offset dollar-for-dollar in expense, this represents an increase of $73 million from Test Year jurisdictional revenue net of fuel expenses of $1.62 billion, or 4.4%. See DAK-4, attached to Mr. Kearns's Direct Testimony. Of this $73 million annual increase, $60 million is primarily related to the Company's customer and electricity sales growth between the Test Year and 2010. As I discussed earlier in my testimony, APS's retail sales of electricity are expected to grow 3.2% between the Test Year (before accounting for the abnormal weather in the Test Year, which is adjusted by the normal weather pro forma) and 2010. Revenues net of fuel expenses grow at this same rate. No base rate increases are assumed in this portion of the attrition calculation.

The remaining $13 million increase in revenues net of fuel expenses is accounted for by the elimination of the write-off in the Test Year of disallowed Palo Verde outage costs.

Q. WHY IS "REVENUE NET OF FUEL" THE APPROPRIATE MEASURE TO DESCRIBE REVENUE LEVELS IN THE ATTRITION PRO FORMA?

A. The most practical reason for using the "revenue net of fuel" measure in the Company's attrition pro forma is that, under the current PSA structure, virtually every dollar all of the costs of fuel in excess of the Company's authorized base fuel rate is deferred until it is collected as revenue. What this means is that the Company's gross revenues and unit revenues may exhibit quite a degree of volatility from one year to the next, driven solely by the level of fuel cost recovery included in that year's rates. Likewise, the Company's fuel expenses will show that same year-to-year volatility. However, if one eliminates that volatility by implicitly assuming that revenues are used first to pay for fuel

expenses and that the remaining "net revenues" are used to cover the Company's fixed costs (that is, costs that are not strictly variable with the level of electricity sales), then a cleaner and more meaningful evaluation can be made with respect to the amount of fixed costs recovered in each year. This is precisely what was done in the unit revenue–unit cost graph on page 6 of my testimony.

Q. HOW WAS THE PROPOSED ATTRITION PRO FORMA DEVELOPED?

A. The Company's proposed attrition pro forma is based on the projected revenue and expense levels expected to be incurred in the year 2010, the first full calendar year in which rates set in this proceeding are expected to be in effect. These projections are presented in an operating income format in Attachment DAK-4 to Mr. Kearns's Direct Testimony.

Mr. Kearns sponsors the attrition pro forma, and discusses the revenue requirement and the capital expenses that make up this pro forma in his testimony.

IX. CONCLUSION

Q. DO YOU HAVE ANY FINAL REMARKS?

A. APS's non-fuel costs are significantly higher than the revenue that APS receives from rates and are increasing at a faster rate than the associated revenues. This is true for a number of reasons, including the Company's rising capital spending obligations in an inflationary cost environment (spending that is necessary both to meet future customer and sales growth and to maintain and improve the Company's existing system), the exhaustion of any economies of scale from which APS may once have benefited, and the reversal of a unit-cost trend that once offset the Company's rising non-fuel costs. The increases in the

Company's non-fuel costs have caused the Company to experience a significant revenue shortfall—a shortfall that will continue into the future without action from the Commission.

With respect to fuel, the increase of natural gas and purchased power prices has been well documented over the last several years and is likely to persist into the future. In addition, the trend in prices for all of the fuel sources for electric generation, including natural gas, coal and nuclear, continues to be upwards, and fuel prices, natural gas in particular, are expected to remain high. Because the vast majority of the Company's incremental load growth is served by natural gas (either through the operation of the Company's own generating facilities or through purchased power), the Company's fuel expense has increased more than expected in 2007, the year used to set the base fuel amount currently in effect. Because these amounts clearly are necessary expenditures required to meet APS's customers' needs, the base fuel rate should be adjusted accordingly to 3.88¢/kWh.

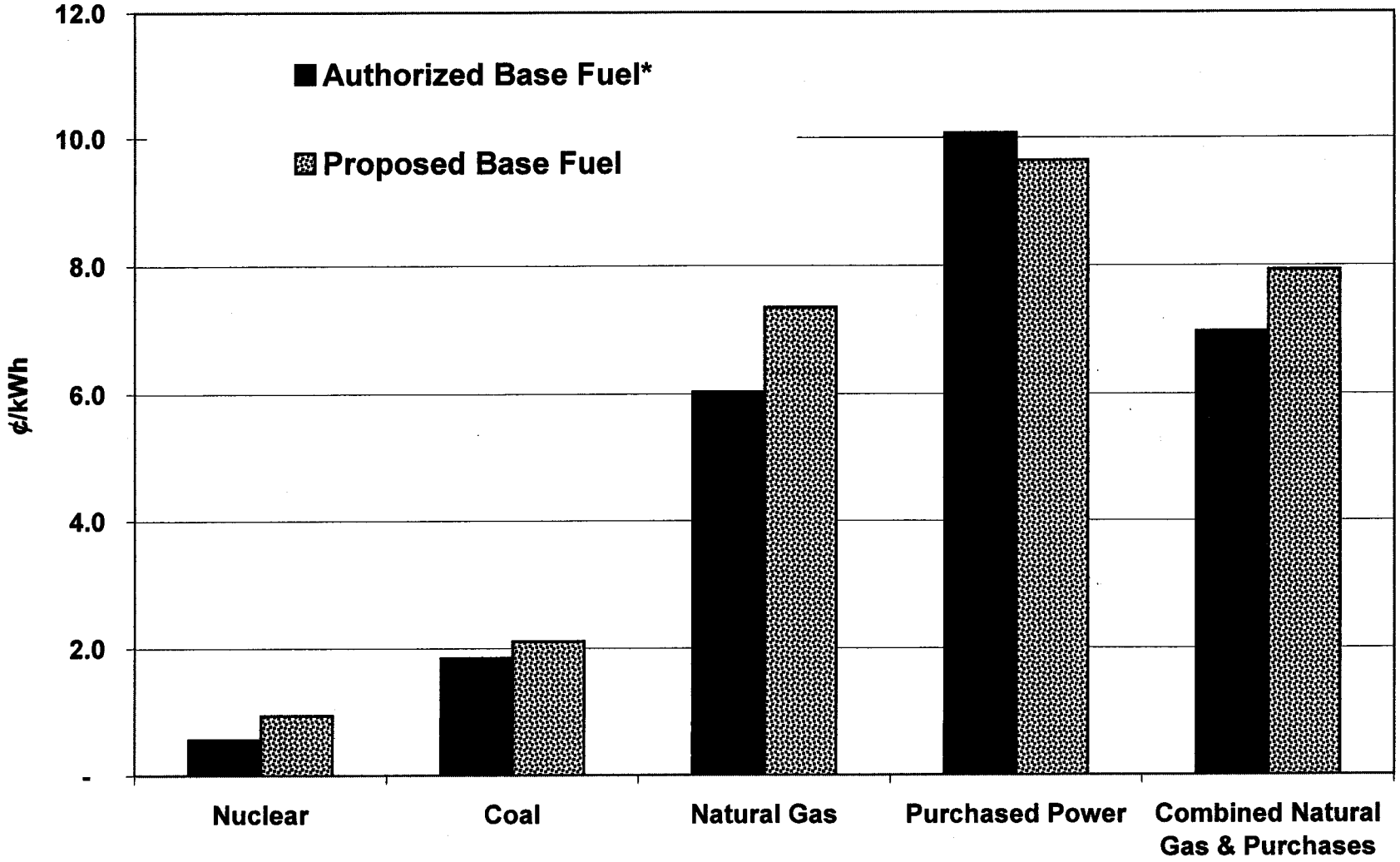
Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Summary of Base Fuel Cost Changes

	Current Authorized Level (2007 Conditions)	Proposed Proforma Level (2010 Conditions)	Proforma vs. Current Authorized
Base Fuel Cost (¢/kWh)	3.2491	3.8783	0.6292
Test Year Period Normalized Sales (GWh)	29,220	29,220	
Base Fuel Expense ($000,000)	949.3	1,133.2	**183.9**
Reduction in Future PSA Revenues			(170.0)
Net Increase to Customers			**13.9**
Reasons for Change ($000,000)			
Prices for Natural Gas, Purchased Power			68.5
Value of Gas and Power Hedge Contracts			(22.4)
Net Effective Price of Natural Gas, Purchased Power			46.1
Increased Share of Natural Gas, Market Purchased Power Mainly Due to Load Growth			30.9
Nuclear Price			28.9
Coal Price			28.5
Capacity Costs			22.9
Increased Share of Renewables			12.3
All Other			14.3
Total			**183.9**

Arizona Public Service Company
Average Fuel Cost by Type of Resource



*Authorized in Decision No. 69663.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 2, column 6
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: BASE FUEL AND PURCHASED POWER
Adjustment to Test Year Operations to Include 2010 Base Fuel and Purchased Power ¢/kWh Costs at Adjusted Test Year Consumption

Line No.	Description		Amount
1.	**ADJUSTED TEST YEAR FUEL AND PURCHASED POWER COSTS (¢/kWh)**		
2.	Normalized 2010 Fuel and Purchased Power Costs (¢/kWh)	3.8783	
3.	Test Year Fuel and Purchased Power Costs (¢/kWh)	3.4346	
4.	Adjustment to Fuel and Purchased Power Costs (¢/kWh)	0.4437	
5.	**ADJUSTED TEST YEAR RETAIL SALES (MWh)**		
6.	Test Year Retail Sales (MWh)	29,171,321	
7.	Pro Forma Adjustments to Test Year Billed Retail Sales (MWh)		
8.	To Adjust to Normal Weather	(445,396)	
9.	To Annualize to December 31, 2007 Customer Level	494,127	
10.	Adjusted Test Year Retail Sales (MWh)	29,220,052	
11.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 4 x Line 10)		$ 129,649
12.	**Operating Income (before income tax)**		**$ (129,649)**
13.	Current Income Tax Rate - 39.36%		(51,030)
14.	**Operating Income After Tax**		**$ (78,619)**

Components of APS Base Fuel Rate
Current Authorized Rate Using 09/29/06 Market Prices

	Fuel Expense ($000)	Production (GWH)	Native Load Sales[1] (GWH)	Share of Production %	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear	44,782	8,578	7,947	27%	0.56	0.15
Coal	225,542	13,181	12,211	41%	1.85	0.77
Natural Gas	413,458	7,401	6,857	23%	6.03	1.40
Purchased Power	207,804	2,227	2,063	7%	10.07	0.71
Purchased Renewables *	25,235	412	382	1%	6.61	0.09
Fixed Gas Transport and Fuel Handling	46,583	-	-	0%		0.16
Total	963,405	31,799	29,460	100%		3.2702
Off System Margin Credit to Retail	(5,656)		26,759			(0.0211)
Net Retail Fuel Cost	957,749					**3.2491**

Native Load Sales	
Retail Sales	28,710
Wholesale Sales	527
Pacificorp Supplemental Sales	223
Total Native Load Sales	29,460

* Excludes above-market premiums.

Components of APS Base Fuel Rate
Proposed Rate Using 3/31/08 Market Prices

	Fuel Expense ($000)	Production (GWH)	Native Load Sales (GWH)	Share of Production %	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear*	76,255	8,844	8,101	26%	0.94	0.25
Coal**	250,286	12,963	11,874	39%	2.11	0.82
Natural Gas	546,519	8,122	7,439	24%	7.35	1.78
Purchased Power***	244,461	2,769	2,536	8%	9.64	0.80
Purchased Renewables****	39,239	772	707	2%	5.55	0.13
Fixed Gas Transport and Fuel Handling	64,453	-	-	0%		0.21
Total Own Load	1,221,213	33,470	30,657	100%		3.9836
ED3 Fuel Cost	(23,730)					(0.0774)
	1,197,483					3.9062
Off System Margin Credit	(8,547)		30,657			(0.0279)
Net Retail Fuel Cost	1,188,936					**3.8783**

Native Load Sales	
Retail Sales	30,115
Traditional Sales for Resale	751
Pacificorp Supplemental Sales	199
ED3	(408)
Total Native Load Sales	30,657

*Excludes ISFSI expense $5,235k
**Excludes Four Corners coal reclamation costs of $1,305k and Navajo coal reclamation costs of $330k.
***Includes native load hedge liquidation margin of $(534)k.
****Excludes above-market premiums.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 3, column 7
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: REMOVE TEST YEAR PSA REVENUE AND DEFERRED FUEL AMORTIZATION
Adjustment to Test Year Retail Operating Revenues and Fuel and Purchased Power Expense
to Remove Retail PSA Revenue and Amortization of Deferred Fuel Related to Prior Periods

Line No.	Description	Amount
1.	**Revenues**	
2.	Remove Test Year PSA Billed and Unbilled Revenue	$ (227,430)
3.	**Expenses**	
4.	Remove Test Year PSA Fuel Deferral Amortization	(240,739)
5.	Operating Revenues less Fuel and Purchased Power Costs	$ 13,309
6.	**Operating Income (before income tax)**	**$ 13,309**
7.	Current Income Tax Rate - 39.36%	5,238
8.	**Operating Income After Tax**	**$ 8,071**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 3, column 8
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: REMOVE TEST YEAR RETAIL DEFERRED FUEL EXPENSE AND NON-CASH MARK-TO-MARKET ACCRUALS
Adjustment to Test Year Retail Fuel and Purchased Power Costs
to Remove Retail PSA Deferred Fuel and Mark-to-Market Accruals

Line No.	Description		Amount
1.	**Fuel and Purchased Power Costs**		
	Current Retail PSA Fuel Deferral	$ 185,385	
	Deferred Mark to Market on Native Load Hedge	(55,181)	
	Total Test Year PSA Fuel Deferral	$ 130,204	
	Non-Cash MTM Accruals	$ 58,855	
	Pro Forma Adjustment to Fuel and Purchased Power Costs		$ 189,059
3.	**Operating Income (before income tax)**		**$ (189,059)**
4.	Current Income Tax Rate - 39.36%		(74,414)
5.	**Operating Income After Tax**		**$ (114,645)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 3, column 9
Total Company
(Thousands of Dollars)

Proforma Adjustment: **NORMALIZE NON-NUCLEAR MAINTENANCE EXPENSE**
Adjustment made to12/31/2007 Test Year operations to reflect normalization of fossil production maintenance expense.

Line No.	Description	Amount
1.	**Expenses**	
2.	Other Operating Expenses	
3.	Operations Excluding Fuel Expenses	$ -
4.	Maintenance	3,290
5.	Proforma Adjustment to Expenses	$ 3,290
6.	**Operating Income (before income tax)**	**$ (3,290)**
7.	Current Income Tax Rate - 39.36%	(1,295)
8.	**Operating Income After Tax**	**$ (1,995)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 10
Total Company
(Thousands of Dollars)

Proforma Adjustment: **NORMALIZE NUCLEAR MAINTENANCE EXPENSE**
Adjustment made to 12/31/2007 Test Year operations to reflect normalization of nuclear production maintenance expense.

Line No.	Description	Amount
1.	**Expenses**	
2.	Other Operating Expenses	
3.	Operations Excluding Fuel Expenses	$ -
4.	Maintenance	(5,556)
5.	Proforma Adjustment to Expenses	$ (5,556)
6.	**Operating Income (before income tax)**	**$ 5,556**
7.	Current Income Tax Rate - 39.36%	2,187
8.	**Operating Income After Tax**	**$ 3,369**

NORMALIZED
PLANNED OUTAGE DAYS VS
2007 Q3 LRF PLANNED OUTAGE DATES

Plant	Avg Unit Capacity (MW)	Normalized Planned Outage MW-Day Target	Normalized Planned Outage Day Target	Required RTSim Adjustment MW-Day	RTSim Adjusted Planned Outage Days	Outage Dates 1	2	3	4
Palo Verde	382	40,354	106	16,824	44	4/3-5/30	10/2-11/17		
Four Corners	156	13,383	106	(3,441)	(22)	4/24-5/14	11/13-11/16	1/12-4/2	
Cholla	205	9,296	36	6,560	32	11/6-12/11			
Navajo	105	4,953	47	(1,155)	(11)	1/30-3/16	4/16-4/17		
WP CC 1-3	85	7,184	85	5,440	64	5/3-5/27	3/1-4/4	12/1-12/25	
OC STM 1-2	110	6,540	59	2,200	20	2/6-3/1	3/20-4/18		
SG STM 1-2	105	6,138	59	1,995	19	2/20-3/19	11/29-12/29		
WP CC4	117	811	7	117	1	2/20-2/26			
WP CC5A	253	5,601	22	(1,265)	(5)	3/27-4/17			
WP CC5B	253	5,668	22	3,289	13	10/16-11/6			
RHK CC1A	246	3,659	15	(4,674)	(19)	1/2-1/16			
RHK CC1B	246	3,690	15	(4,674)	(19)	1/2-1/16			
RHK CC2A	246	2,864	12	(6,888)	(28)	3/13-3/13	10/16-10/25		
RHK CC2B	246	3,492	14	(6,150)	(25)	3/13-3/14	10/16-10/27		
OC CT 1-2	55	2,035	37	1,430	26	11/13-12/1	3/8-3/26		
SG CT 1-2	55	1,219	22	(495)	(9)	3/22-4/9	2/8-2/10		
SG CT3	79	246	3	(79)	(1)	10/11-10/13			
WP CT 1-2	55	409	1,547	(1,925)	(35)	1/18-1/18	5/15-5/20		
YUCCA CT 1-4	37	2,182	11,377	2,573	70	3/15-4/17	3/22-4/24	2/15-3/2	
Douglas CT	16	113	7	48	3	5/14-5/20			
Sundance CT 1-10	42	2,142	25,408	(1,008)	(24)	10/4-10/9	11/8-11/13	2/8-2/13	3/8-3/13
Gila Toll CC 4A	246	10,824	44	8,610	35	2/27-4/6	5/9-5/13		
Gila Toll CC 4B	246	11,562	47	9,348	38	2/27-4/9	5/9-5/13		

Arizona Public Service Company
Comparison of Current Authorized EFOR to Proforma EFOR
(%)

	Current Authorized Level (2007 Conditions)	Proforma Level (2010 Conditions)
Nuclear	2.5	2.5
Four Corners	8.5	7.7
Cholla	5.8	5.3
Navajo	5.3	5.0
West Phoenix CC 1-3	7.0	7.0
West Phoenix CC 4	7.0	7.0
West Phoenix CC 5	10.0	10.0
Redhawk	7.5	7.5
Steam Plants	7.7	6.5
Gas Turbines	7.0	6.5

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 11
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **NORMALIZE WEATHER CONDITIONS**
Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2007.

Line No.	Description		Amount
1.	**Revenues**		
2.	Operating Revenue		$ (39,380)
3.	Adjustment to sales (MWh) for the difference between customer annualized	(445,396)	
4.	sales and actual sales		
5.	**Expenses**		
6.	Fuel and Purchased Power Expenses:		
7.	Adjustment to Sales (MWh)	(445,396)	
8.	Test Year Fuel and Purchased Power Costs (¢/kWh)	3.4346	
9.	Proforma Adjustment to Fuel and Purchased Power Expenses		(15,298)
10.	Operating Revenues Less Fuel and Purchased Power Expenses		$ (24,082)
11.	Other Operating Expenses		
12.	Adjustment to Sales (MWh)	(445,396)	
13.	Test Year Average OATT Expense (¢/kWh)	0.4760	
14.	Proforma Adjustment to OATT Expense		(2,120)
15.	**Operating Income (before income tax)**		**$ (21,962)**
16.	Current Income Tax Rate - 39.36%		(8,644)
17.	**Operating Income After Tax**		**$ (13,318)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 12
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **ANNUALIZE CUSTOMER LEVELS**
Adjustment to Test Year operations to reflect the annualization of customer levels at December 31, 2007.

Line No.	Description		Amount
1.	**Revenues**		
2.	Operating Revenue		$ 41,846
3.	Adjustment to sales (MWh) for the difference between customer annualized	494,127	
4.	sales and actual sales		
5.	**Expenses**		
6.	Fuel and Purchased Power Expenses:		
7.	Adjustment to Sales (MWh)	494,127	
8.	Test Year Fuel and Purchased Power Costs (¢/kWh)	3.4346	
9.	Proforma Adjustment to Fuel and Purchased Power Expenses		16,971
10.	Operating Revenues Less Fuel and Purchased Power Expenses		$ 24,875
11.	Other Operating Expenses		
12.	Adjustment to Sales (MWh)	494,127	
13.	Test Year Average OATT Expense (¢/kWh)	0.4760	
14.	Proforma Adjustment to OATT Expense		2,352
15.	**Operating Income (before income tax)**		**$ 22,523**
16.	Current Income Tax Rate - 39.36%		8,865
17.	**Operating Income After Tax**		**$ 13,658**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 13
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **NORMALIZE UNCOLLECTED FIXED COSTS**
Adjustment to Test Year operations to reflect uncollected fixed costs due to Demand Side Management.

Line No.	Description		Amount
1.	**Revenues**		
2.	Operating Revenue		$ (16,789)
3.	**Expenses**		
4.	Other Operating Expenses		
5.	Adjustment to Sales (MWh)	(220,696)	
6.	Test Year Average OATT Expense (¢/kWh)	0.4760	
7.	Proforma Adjustment to OATT Expense		(1,051)
8.	**Operating Income (before income tax)**		**$ (15,738)**
9.	Current Income Tax Rate - 39.36%		(6,194)
10.	**Operating Income After Tax**		**$ (9,544)**

Jason C. La Benz

DIRECT TESTIMONY OF JASON C. LA BENZ

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

I. INTRODUCTION 1

II. SUMMARY 2

III. HISTORICAL AND TEST YEAR ACCOUNTING DATA 4

A. Summary Schedules 5

B. Rate Base Schedules 6

C. Test Year Income Statements 10

D. Cost of Capital 11

E. Financial Statements and Statistical Schedules 12

F. Projections and Forecasts 14

IV. PRO FORMA ADJUSTMENTS TO TEST YEAR 15

A. Pro Forma Adjustments Annualizing the Implementation of Decision No. 69663 16

1. Annualize Spent Fuel Storage Costs 16

2. Annualize Four Corners Coal Reclamation Costs 16

3. Annualize Bark Beetle Remediation Costs 17

4. Annualize Depreciation and Amortization per Decision 69663 17

5. Remove Test Year Surcharges 18

6. Annualize Sundance Overhaul Maintenance Expense 18

7. West Phoenix Unit 4 Regulatory Disallowance 19

8. Interest Expense on Customer Deposits 19

9. Depreciation Expense – 2007 Depreciation Study 20

10. Annualize Payroll 20

11. Normalize Employee Benefits 21

12. Normalize Income Tax Expense Including Synchronization of Interest 22

13. Annualize Property Tax Expense 22

14. Amortize Navajo Coal Reclamation Costs 23

B. Other Pro Formas Including Out-Of-Period Adjustments 24

1. Annualize Workforce Reduction Savings 24

2. Normalize Customer Bad Debt Expense 25

3. Miscellaneous Out-of-Period Adjustments 25

RCND by Major Plant Accounts ..... Attachment JCL-1

RCN by Major Plant Accounts ..... Attachment JCL-2

Computation of Working Capital ..... Attachment JCL-3

Detail of Pro forma Adjustments:

Annualize Spent Fuel Storage Costs ..... Attachment JCL-4

Annualize Four Corners Coal Reclamation Costs ..... Attachment JCL-5

Annualize Bark Beetle Remediation Costs ..... Attachment JCL-6

Annualize Depreciation and Amortization per Decision No. 69663 Attachment JCL-7

Remove Test Year Surcharges ..... Attachment JCL-8

Annualize Sundance Overhaul Maintenance Expense ..... Attachment JCL-9

West Phoenix Unit 4 Regulatory Disallowance [Rate Base] ..... Attachment JCL-10

West Phoenix Unit 4 Regulatory Disallowance [Operating Inc.] ... Attachment JCL-11

Interest Expense On Customer Deposits ..... Attachment JCL-12

Depreciation Expense – 2007 Depreciation Study ..... Attachment JCL-13

Annualize Payroll ..... Attachment JCL-14

Normalize Employee Benefits ..... Attachment JCL-15

Normalize Income Tax Expense/ Interest Synchronization ..... Attachment JCL-16

Annualize Property Tax Expense ..... Attachment JCL-17

Amortize Navajo Coal Reclamation Costs ..... Attachment JCL-18

Annualize Workforce Reduction Savings ..... Attachment JCL-19

Normalize Customer Bad Debt Expense ..... Attachment JCL-20

Miscellaneous Out-of-Period Adjustments ..... Attachment JCL-21

TESTIMONY OF JASON C. LA BENZ
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

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

A. My name is Jason C. La Benz. I am the Manager of Financial Reporting for Arizona Public Service Company ("APS" or the "Company"), a subsidiary of Pinnacle West Capital Corporation ("Pinnacle West"). I am responsible for the financial accounting, revenue and regulatory accounting, accounts receivable, and cash control functions at Pinnacle West and APS. My business address is 400 North Fifth Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Business with a major in Accounting from Arizona State University in 1982. I joined APS in May of 1982 as a staff accountant and have spent the last 26 years working for APS and Pinnacle West in Financial Accounting, Plant Accounting, Financial Planning, and the Tax Department.

Before my promotion to Manager of Financial Reporting in 1997, I was responsible for the plant accounting function at APS as the supervisor of that department. I am a Certified Public Accountant and a member of the Edison Electric Institute's Corporate Accounting Committee.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony addresses the historical accounting information and pro forma adjustments required by the Standard Filing Requirements ("SFR") of the Arizona Corporation Commission ("Commission") to support the Company's rate case filing. I sponsor the historical information related to the Test Year (twelve months ended December 31, 2007) and any prior years presented on the following SFR Schedules (APS witness Daniel Kearns sponsors any projected information contained in these schedules):

- A-2 through A-5 – Summary Schedules
- B-1, B-3 through B-5 – Rate Base Schedules
- C-1 – Test Year Income Statements
- C-3 – Computation of Gross Revenue Conversion Factor
- D-1 through D-4 – Cost of Capital
- E-1 through E-9 – Financial Statements and Statistical Schedules
- F-1 through F-3 – Projections and Forecasts

I will also provide direct testimony on certain pro forma adjustments made to the Test Year on SFR Schedules B-2 and C-2. In large part, the pro forma adjustments merely reflect a full year's annualization or normalization of adjustments already required in ACC Decision No. 69663 (June 28, 2007). Specifically, I will be sponsoring the "Total Company" column for the following pro forma on SFR Schedule B-2:

- West Phoenix Unit 4 Regulatory Disallowance

Additionally, I will be sponsoring the "Total Company" columns for the following pro formas on SFR Schedule C-2:

- Annualize Spent Fuel Storage Costs
- Annualize Four Corners Coal Reclamation Costs
- Annualize Bark Beetle Remediation Costs
- Annualize Depreciation and Amortization Per Decision 69663
- Remove Test Year Surcharges
- Annualize Sundance Overhaul Maintenance Expense
- West Phoenix Unit 4 Regulatory Disallowance
- Interest Expense on Customer Deposits
- Depreciation Expense – 2007 Depreciation Study
- Annualize Payroll
- Normalize Employee Benefits
- Normalize Income Tax Expense Including Synchronization of Interest
- Annualize Property Tax Expense
- Amortize Navajo Coal Reclamation Costs
- Annualize Workforce Reduction Savings
- Normalize Customer Bad Debt Expense
- Miscellaneous Out-Of-Period Adjustments

These adjustments are consistent with prior filings and represent "normalizations" or "annualizations" as discussed below. The operating income pro formas also include an income tax calculation at the current combined federal and state statutory income tax rates. The SFR Schedule C-2 pro forma for the West Phoenix Unit 4 Regulatory Disallowance includes a calculation for the synchronization of interest expense used in the calculation of federal and state income tax expense.

I will discuss and explain the factor used to gross-up operating income to account for income taxes, as presented on SFR Schedule C-3. I will also present testimony concerning the capital structure of the Company and provide APS' actual overall cost of capital, as presented on SFR Schedules D-1 through D-4. (Mr. Kearns will discuss the projected information on SFR Schedules D-1 through D-3). This discussion will include information on the cost of equity provided by Dr. William Avera, APS' return on equity ("ROE") witness, as well as the Company's cost of debt. In addition, I will sponsor the various schedules relating to the Company's financial statements on SFR Schedules E-1 through E-9. SFR Schedule E-6 refers only to "combination" utilities (e.g., electric and gas) and thus is not applicable to APS. Finally, I will sponsor the Test Year data on SFR Schedules F-1 through F-3. These schedules also include projected income statements and projected changes in financial position. Once again, Mr. Kearns will address and sponsor the projected information on those schedules.

III. HISTORICAL AND TEST YEAR ACCOUNTING DATA

Q. PLEASE DESCRIBE THE ACCOUNTING INFORMATION CONTAINED WITHIN THE SFR SCHEDULES THAT YOU ARE SPONSORING.

A. My testimony covers historical accounting data, including the actual data for the Test Year. The majority of this information is disclosed directly or indirectly in both the APS and the consolidated Pinnacle West audited financial statements, which are included in filings made with the Securities and Exchange Commission ("SEC") for the relevant years.

Additionally, all of the accounting information provided in my testimony complies with Generally Accepted Accounting Principles ("GAAP"). These are the principles that accounting professionals use to prepare financial statements. One major goal of GAAP is to make financial statements comparable from year to year, from industry to industry, and from jurisdiction to jurisdiction. In addition to GAAP, APS' accounting practices comply with other applicable utility accounting standards, such as the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, which this Commission has adopted. *See* A.A.C. R14-2-212(G)(2).

In large part, my testimony supports the testimony of other APS witnesses. The direct testimony of Mr. Kearns addresses financial projections to actual Test Year data. APS witness David Rumolo focuses on the jurisdictional allocation of APS revenues, costs, and Rate Base items for the actual Test Year and all the pro forma adjustments. Dr. Avera's testimony addresses the Company's ROE.

A. *Summary Schedules*

Q. PLEASE DESCRIBE THE HISTORICAL INFORMATION ON SFR SCHEDULES A-2 THROUGH A-5.

A. These summary schedules provide the "Summary Results of Operations," the "Summary of Capital Structure," the "Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service" and the "Summary Changes in Financial Position" for the Test Year and the prior two calendar years. These schedules also include projected information. I am sponsoring the historical data for the Test Year and prior calendar years. Mr. Kearns is sponsoring the projected information on these schedules.

B. *Rate Base Schedules*

Q. PLEASE DESCRIBE THE INFORMATION ON SFR SCHEDULES B-1 THROUGH B-5.

A. These schedules provide summary and detail information of our Original Cost and RCND Rate Base, including the related pro formas needed to present an adjusted Rate Base as of the end of the Test Year. I am sponsoring the "Total Company" portion of these schedules and certain pro forma adjustments. Mr. Rumolo is sponsoring the "ACC" portion, in that Mr. Rumolo allocated the "Total Company" figures to the ACC jurisdiction.

Q. PLEASE SUMMARIZE THE ADJUSTED TEST YEAR ORIGINAL RATE BASE PROPOSED BY APS.

A. As of December 31, 2007, APS is proposing a Total Company Original Cost Rate Base ("OCRB") of $6,235,866,000. This represents an increase of $428,066,000 over the unadjusted amount. The jurisdictional allocation of the adjusted OCRB is $5,359,964,000. The requested adjustments to the test year period amounts are summarized in SFR Schedule B-2.

Q. WHAT IS MEANT BY THE TERMS "RCND" AND "RCN" AS USED IN YOUR TESTIMONY?

A. The Commission regulations define Reconstructed Cost New Less Depreciation or "RCND" as:

> An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis (A.A.C. R14-2-103(A)(3)(n)).

Thus, Reconstructed Cost New ("RCN") refers to the estimated costs of utility property that would be incurred if APS were to reproduce or reconstruct the property as new, using current cost levels. RCND is the net amount that results after deducting accumulated depreciation and amortization (both of which are also restated in current dollars) from the RCN amount.

Q. WHAT IS SHOWN ON SFR SCHEDULE B-4?

A. SFR Schedule B-4 presents the RCN and RCND amounts of APS' utility properties. These amounts were determined using a Handy-Whitman RCN Study performed by the Company. See Attachment JCL-1.

Q. BASED ON YOUR STUDY, WHAT IS THE RCN OF APS' UTILITY PROPERTY DEVOTED TO SERVICE TO THE PUBLIC AS OF THE END OF THE TEST YEAR?

A. Total RCN for APS' utility property is approximately $21.4 billion. This total amount is shown in column (c) of Attachment JCL-2 and in column (A) of SFR Schedule B-4, page 2 of 2.

Q. WOULD YOU PLEASE EXPLAIN HOW RCND WAS CALCULATED AS SHOWN ON SFR SCHEDULE B-4?

A. To arrive at RCND, RCN column (A) is multiplied by a "condition percent," also known as a net book value percent, which is shown in column (B). RCND is shown in column (C). The condition percent used to convert RCN to RCND is calculated by first taking the original cost less accumulated depreciation (in other words, the net book value) for all depreciable plant for each FERC account. This is divided by the original cost for each FERC account to arrive at the condition percent. In other words, the condition percent is the percentage that results when comparing original cost less accumulated depreciation to the original cost of plant in service.

For example, assume that distribution lines have an original cost of $400,000, and accumulated depreciation of $250,000. The original cost less accumulated depreciation would be $150,000, which is $400,000 minus $250,000. Also, assume the distribution lines were purchased in 1985 and have a RCN value of $632,000. Using these assumptions, the condition percent is calculated by dividing original cost less accumulated depreciation by original cost, or $150,000/$400,000, resulting in 37.5%. Multiplying RCN by the condition percent yields RCND. In this hypothetical, $632,000 x 37.5% = $237,000.

Q. WOULD YOU PLEASE EXPLAIN SFR SCHEDULE B-4A?

A. SFR Schedule B-4A shows the computation of adjusted jurisdictional RCND Rate Base as of December 31, 2007. Column (A) presents data for Total RCND Rate Base. Mr. Rumolo provided the jurisdictional allocations of the RCND Rate Base split between "ACC" and "Other," which is presented in columns (B) and (C) respectively.

Q. HOW DID YOU ARRIVE AT THE AMOUNTS SHOWN ON LINES 9 THROUGH 24 OF SFR SCHEDULE B-4A?

A. The amounts shown on lines 9 through 24 of SFR Schedule B-4A for other Rate Base elements were obtained from SFR Schedule B-1, page 2 of 2 column (A). As in past presentations and consistent with past Commission practice, the RCND of these specific Rate Base elements are stated at their original cost levels, as these elements do not change in value with the passage of time.

Q. WOULD YOU PLEASE EXPLAIN LINES 26 AND 27 OF SFR SCHEDULE B-4A?

A. The amounts shown on line 26 represent the RCND Rate Base as of December 31, 2007. However, the end of Test Year data needs to be adjusted to more closely reflect the value of certain items of property when the proposed rates

become effective. Therefore, it was necessary to also reflect the pro forma Rate Base adjustments in the RCND Rate Base. The RCND pro forma adjustments are shown in detail on SFR Schedule B-3. The total is shown on line 27 of SFR Schedule B-4A.

Q. WHAT IS THE TOTAL ADJUSTED RCND RATE BASE?

A. The total Company RCND Rate Base, as adjusted, is approximately $11.7 billion. This is shown on SFR Schedule B-4A, column (A), line 28.

Q. PLEASE EXPLAIN COMPUTATION OF WORKING CAPITAL ON SFR SCHEDULE B-5.

A. This SFR Schedule outlines the computation of the allowance for working capital of $159,052,000 included in the Company's Rate Base (see Attachment JCL-3). Working capital is a measure of investor funding of daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations. Working capital includes materials and supplies, fuel inventories, prepayments and cash working capital. Working capital is an investment just like other capital requirements, such as power plants and transmission and distribution infrastructure; thus, it is part of APS' Rate Base. My testimony presents the calculation of the allowance for working capital, which includes a cash working capital component determined using a lead/lag study, which study is required by Decision No. 55931.

Q. HOW WAS THE CASH WORKING CAPITAL CALCULATED?

A. APS calculated the net cash working capital by performing a "lead/lag" study. A lead/lag study establishes the amount of investor funds used to maintain utility operations from the time expenditures are made to the time revenues are collected as a reimbursement for that utility service. The Company used the

number of lead/lag study days derived from a calendar year 2007 study and applied this information to the Test Year income statement expenses.

C. *Test Year Income Statements*

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULE C-1.

A. SFR Schedule C-1 is a summary of the Company's adjusted Test Year income statement. I am sponsoring the actual Test Year data in the first column of SFR Schedule C-1, page 1. This information provides the baseline from which pro forma adjustments are made and shows operating income and net income for the Test Year.

Q. ARE YOU SPONSORING ANY OTHER RELATED SFR SCHEDULES?

A. Yes. I am sponsoring certain pro forma adjustments on SFR Schedule C-2. SFR Schedule C-2 presents the pro forma adjustments to the Company's Test Year operating income. I will discuss these adjustments in detail later in my testimony (see section IV "Pro Forma Adjustments To Test Year"). I am also sponsoring SFR Schedule C-3, which shows the computation of the gross revenue conversion factor.

Q. PLEASE DESCRIBE SFR SCHEDULE C-3.

A. SFR Schedule C-3 calculates the factor applied to "gross-up" income to account for income taxes. We apply this factor to operating income to ensure income tax expense is reflected in the requested revenue requirement. The Gross Revenue Conversion factor of 1.6491 (shown on line 5) is an algebraic transformation of APS' composite federal and state income tax rate of 39.36 percent. This factor is used on SFR Schedule A-1 (line 7) to arrive at the increase or decrease in Gross Revenue Requirements necessary to account for income taxes.

D. *Cost of Capital*

Q. PLEASE DISCUSS THE COST OF CAPITAL INFORMATION THAT YOU ARE SPONSORING.

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital. I am sponsoring the Test Year data in this schedule. SFR Schedule D-2 presents supporting detail for the long-term debt summarized on SFR Schedule D-1. SFR Schedule D-3, which addresses preferred stock, is included in the Company's schedules for the sake of completeness. SFR Schedule D-3 is not directly applicable because APS did not have any outstanding preferred stock as of December 31, 2007. SFR Schedule D-4 addresses the Company's cost of common equity.

Q. WHAT IS THE COST OF CAPITAL THE COMPANY IS REQUESTING?

A. The weighted cost of capital the company is requesting is 8.86% as set forth on SFR Schedule D-1.

Q. PLEASE DISCUSS IN MORE DETAIL THE COMPANY'S OUTSTANDING LONG-TERM DEBT AS OF THE END OF THE TEST YEAR.

A. At the end of the Test Year, approximately 77% of APS' outstanding long-term debt consisted of unsecured notes with a weighted average interest rate of approximately 6.1% ($135,703,000 divided by $2,226,430,000). Most of the remaining long-term debt consisted of tax-advantaged pollution control bonds. This debt has a weighted average interest rate of approximately 4.5%. APS also has a small amount of interest attributable to capital lease obligations and amortization of losses and gains on reacquired debt, both of which are classified as net interest expense on SFR Schedule D-2.

Q. WHAT WAS APS' CAPITAL STRUCTURE AT THE END OF THE TEST YEAR?

A. APS' total long-term debt and common equity was approximately $6.25 billion. This amount includes approximately $2.89 billion in long-term debt (including current maturities) and approximately $3.36 billion in common equity. APS' adjusted capital structure at the end of the Test Year was approximately 46.21% debt and 53.79% equity.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE CAPITAL STRUCTURE?

A. I have applied two pro forma adjustments to the December 31, 2007 actual cost of capital. These adjustments remove impacts to equity of non-cash accounting adjustments for pension and derivatives. Since these adjustments were small in comparison to total equity, there is no significant impact on the capital structure.

Q. WHAT IS THE RETURN ON EQUITY THE COMPANY IS REQUESTING?

A. Dr. Avera concludes in his testimony that the fair rate of return on equity range for APS was 11.25% to 12.5%. For the purposes of this filing, the Company is proposing a return on common equity of 11.5%.

E. *Financial Statements and Statistical Schedules*

Q. PLEASE SUMMARIZE THE INFORMATION PRESENTED ON SFR SCHEDULES E-1 THROUGH E-9.

A. These schedules relate to historical financial and accounting information, as well as the notes to the financial statements. SFR Schedule E-6 is only required for combined electric and gas utilities and therefore does not apply to APS.

Q. PLEASE DISCUSS SFR SCHEDULES E-1 THROUGH E-4.

A. These schedules present APS' balance sheets, income statements, statements of cash flow and changes in stockholders' equity for the Test Year period and the two prior calendar years. The calendar year financial statements were included in SEC Form 10-K filings for the relevant years.

Q. PLEASE DISCUSS SFR SCHEDULE E-5.

A. SFR Schedule E-5 is a detailed statement of utility plant included in the Company's Rate Base, broken down by FERC account under the Uniform System of Accounts. The first page of SFR Schedule E-5 is a summary of gross plant in service, accumulated depreciation, nuclear fuel, construction work in progress, and plant held for future use. The remainder of the schedule presents supporting detail for each FERC plant account.

Q. WHAT INFORMATION IS PROVIDED ON SFR SCHEDULE E-7?

A. SFR Schedule E-7 provides detailed information concerning APS' sales (in kWh), number of customers and average usage per customer over the last two years, including the Test Year. This information is contained in or derived from APS' FERC Form 1 filings for the applicable periods. The information in SFR Schedule E-7 is separated by customer classes to show residential, commercial, industrial, irrigation, public street and highway lighting, other sales to public authorities, and sales for resale.

Q. PLEASE DISCUSS SFR SCHEDULE E-8.

A. SFR Schedule E-8 provides a breakdown of APS' tax expense incurred during the Test Year and the two prior calendar years, for federal, state and local taxes.

Q. PLEASE DISCUSS SFR SCHEDULE E-9.

A. SFR Schedule E-9 presents the Company's SEC Financial Statements including the footnotes. The footnotes include, but are not limited to, the Company's accounting policies for depreciation, capitalized interest and income taxes. The footnotes also provide additional detailed information related to the income statements, the balance sheets and statements of cash flow. The Company is also providing a copy of Form 10-K for 2007 as an attachment to SFR Schedule E-9.

F. *Projections and Forecasts*

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULES F-1 AND F-2.

A. SFR Schedule F-1 presents income statements for projected calendar years, compared with actual Test Year results, at present and proposed rates. SFR Schedule F-2 shows projected changes in the financial position of the Company for future calendar years compared with the Test Year, at present and proposed rates. I am sponsoring the historical Test Year data in the first column of each of these SFR Schedules. Mr. Kearns will address the projected data on these same SFR Schedules.

Q. PLEASE DISCUSS SFR SCHEDULE F-3.

A. SFR Schedule F-3 presents projected annual construction expenditure requirements, by property classification, for three years subsequent to the Test Year. I am sponsoring the actual Test Year information. Again, Mr. Kearns will address the projected data on this schedule.

IV. PRO FORMA ADJUSTMENTS TO TEST YEAR

Q. HOW IS YOUR TESTIMONY REGARDING PRO FORMA ADJUSTMENTS ORGANIZED?

A. I will first discuss items that solely reflect the implementation of or which are consistent with Decision No. 69663 and adjust the Test Year to include the effects of that Decision (Attachments JCL-4 through JCL-18). I will discuss other operating income pro formas to normalize out-of-period items (Attachments JCL-19 through JCL-21). All of the pro forma adjustments discussed in my testimony reflect Total Company amounts prior to any jurisdictional allocation and are reflected on either SFR Schedule B-2 or SFR Schedule C-2.

Q. WHAT ARE PRO FORMA ADJUSTMENTS?

A. Pro forma adjustments are adjustments made to a historical test year to reflect conditions during the period in which rates are to be in effect. Because the Company has used a historical test year, it is necessary to adjust recorded revenues and expenses for known and measurable changes. Pro forma adjustments commonly include normalizations, annualizations and out-of-period adjustments.

Q. WHAT ARE "NORMALIZATIONS"?

A. Normalization adjustments compensate or adjust for unusual levels of operations experienced during the Test Year period. These adjustments generally relate to items that are abnormal in amount or nonrecurring in nature and are made to better reflect what is believed to be an ongoing level of operations.

Q. WHAT ARE "ANNUALIZATIONS"?

A. Annualization adjustments recognize that some events occurring during the test period are ongoing and must be adjusted to reflect their impact over an entire

twelve-month period. One example of an annualization is for the payroll increases that happen during the Test Year. Since payroll costs will be higher on an ongoing basis than what was recorded during the Test Year, an adjustment must be made to reflect the prospective level of costs.

Q. WHAT IS AN "OUT-OF-PERIOD" ADJUSTMENT?

A. Out-of-period adjustments remove expenses or revenues properly recorded during the Test Year, but which are associated with operations from another year.

A. *Pro Forma Adjustments Annualizing the Implementation of Decision No. 69663*

1. Annualize Spent Fuel Storage Costs

Q. PLEASE DESCRIBE THIS ADJUSTMENT.

A. This pro forma adjustment for Spent Fuel Storage adjusts the Test Year to reflect the full year of the new cost level approved in Decision No. 69663. This results in a reduction to pre-tax operating income of $1,289,000 (See Attachment JCL-4 and SFR Schedule C-2, page 5, column 14).

2. Annualize Four Corners Coal Reclamation Costs

Q. PLEASE DESCRIBE THIS ADJUSTMENT.

A. This pro forma adjustment for Four Corners Coal Reclamation adjusts the Test Year to reflect a full year of the new amortization level as approved by Decision No. 69663. This results in a reduction to pre-tax operating income of $334,000 (See Attachment JCL-5 and SFR Schedule C-2, page 5, column 15).

3. Annualize Bark Beetle Remediation Costs

Q. PLEASE DESCRIBE THIS ADJUSTMENT.

A. Decision No. 69663 ordered amortization of these previously deferred costs over a three-year period beginning July 1, 2007. The total deferral balance at June 30, 2007 was $11,508,000, resulting in an annual amortization of $3,836,000. Because the Test Year only contained amortization from July 1, 2007 through December 31, 2007 (6 months), a pro forma is necessary to add 6 months of amortization resulting in a full 12-month amortization of the bark beetle remediation costs in the Test Year. This results in a reduction to pre-tax operating income of $1,918,000 (See Attachment JCL-6 and SFR Schedule C-2, page 6, column 16).

4. Annualize Depreciation and Amortization per Decision No. 69663

Q. WHAT WERE THE RESULTS OF IMPLEMENTING THE DEPRECIATION AND AMORTIZATION RATES AS APPROVED IN DECISION NO. 69663?

A. Adjusting the Test Year to reflect the increased depreciation and amortization expense by applying the rates approved in Decision No. 69663 to the end of the Test Year plant balances results in a reduction to pre-tax operating income of $10,691,000 (See Attachment JCL-7 and SFR Schedule C-2, page 6, column 17).

Q. IS THIS THE ONLY PRO FORMA RELATED TO DEPRECIATION AND AMORTIZATION?

A. No. In addition to this pro forma implementing Decision 69663, the Company has submitted one other depreciation related pro forma to update the Company's depreciation as a result of a more recent depreciation study. This will be discussed in more detail below. Additionally, specific pro formas for new

additions to plant also include depreciation expense adjustments using the depreciation rates resulting from the depreciation study.

5. Remove Test Year Surcharges

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR SURCHARGES AND ADJUSTORS.

A. The adjustment is made to exclude from revenue and expense the amounts collected under surcharges and adjustors outside of base rates; specifically, the Environmental Portfolio Standard ("EPS") surcharge, Competition Rules Compliance Charge, and Regulatory Assessment charges. These items are not collected as part of base rates so must be excluded from the Test Year revenue in order to calculate new base rates. The pro forma also removes from expense the associated costs spent. In addition, the pro forma ensures that the Test Year reflects the $6,000,000 total amount authorized to be collected and spent as part of base rates under the EPS. This results in a reduction to pre-tax operating income of $1,436,000 (See Attachment JCL-8 and SFR Schedule C-2, page 6, column 18).

6. Annualize Sundance Overhaul Maintenance Expense

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT RELATED TO OPERATIONS AND MAINTENANCE ("O&M") AT THE SUNDANCE UNITS.

A. Decision No. 69663 ordered the Company to record a current period expense and a corresponding regulatory liability equal to the amount collected in base rates related to the Sundance units periodic overhaul maintenance beginning July 1, 2007. The regulatory liability will be reduced in the future when these overhaul costs are actually incurred. This adjustment reflects 6 months worth of the approved level of overhaul maintenance expense (6 months were already

reflected in the Test Year), resulting in a reduction to pre-tax operating income of $805,000 (See Attachment JCL-9 and SFR Schedule C-2, page 7, column 19).

7. West Phoenix Unit 4 Regulatory Disallowance

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE.

A. In accordance with GAAP, this disallowance was only recorded for regulatory purposes. Consequently, a pro forma adjustment is needed to reduce Rate Base by the disallowed amount. Accordingly, the Rate Base reduction for the West Phoenix Unit 4 regulatory disallowance at December 31, 2007 is $10,064,000 (See Attachment JCL-10 and SFR Schedule B-2, page 2, column 6).

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE DEPRECIATION EXPENSE RELATED TO THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE?

A. Yes. The operating income pro forma reflects an annual reduction in depreciation expense. This results in an increase to pre-tax operating income of $329,000 (See Attachment JCL-11 and SFR Schedule C-2, page 7, column 20).

8. Interest Expense on Customer Deposits

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR INTEREST EXPENSE ON CUSTOMER DEPOSITS.

This pro forma adjustment reflects the annualized interest cost associated with customer deposits as an operating expense. This treatment conforms to the approach utilized by the Commission in previous Company rate cases. This pro forma adjustment was calculated by applying the 3.17 percent annual 2008 interest rate to the December 31, 2007 outstanding deposit balance. The annual interest rate is the rate required by APS Schedule 1 for customer deposits - the established one-year Treasury Constant Maturities rate, effective on the first business day of each year (in this instance, January of 2008), as published on the

Federal Reserve website. The result of this pro forma is a reduction to pre-tax operating income of $2,261,000 (See Attachment JCL-12 and SFR Schedule C-2, page 7, column 21).

9. Depreciation Expense – 2007 Depreciation Study

Q. WHAT OTHER ADJUSTMENTS HAS THE COMPANY MADE TO DEPRECIATION AND AMORTIZATION EXPENSE?

A. For this filing, APS witness Dr. Ronald White performed a 2007 Depreciation Study using data as of December 31, 2007. Using Dr. White's Depreciation Study, APS has updated depreciation rates from the rates authorized in Decision No. 69663. APS is asking Commission approval of these depreciation rates in this proceeding. Please refer to Dr. White's testimony for further discussion. This pro forma adjustment reduced depreciation expense and thus results in an increase to pre-tax operating income of $9,076,000 (See Attachments JCL-13 and SFR Schedule C-2, page 8, column 22).

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS EXISTING AMORTIZATION RATES?

A. No. APS is not requesting any change to the amortization rates authorized in Decision No. 69663.

10. Annualize Payroll

Q. DID APS ANNUALIZE TEST YEAR PAYROLL?

A. Yes. This pro forma adjustment increases Test Year expense mainly as a result of higher costs associated with a rising average salary and increased employee levels. This pro forma adjustment annualizes the Test Year payroll and payroll tax expense to March 2008 employee levels and includes the actual March 2008 wage levels for performance review employees and March 2009 contract wage levels for union employees. This results in a reduction to pre-tax operating

income of $20,838,000 (See Attachment JCL-14 and SFR Schedule C-2, page 8, column 23).

Q. DOES THIS TOTAL PAYROLL ADJUSTMENT ONLY AFFECT O&M?

A. Yes. This adjustment excludes capitalized payroll costs. This O&M adjustment was estimated by calculating the percentage of APS' O&M payroll to total payroll during the Test Year. The pro forma O&M payroll and payroll taxes were allocated to operations and maintenance based on the Test Year payroll amounts recorded for each of these activities.

11. Normalize Employee Benefits

Q. PLEASE EXPLAIN THE NEED FOR THE EMPLOYEE BENEFITS PRO FORMA ADJUSTMENT.

A. This adjustment is necessary to appropriately recognize the costs associated with pension and Other Post-retirement Employee Benefit ("OPEB") plans, which are primarily medical benefits for eligible retirees. This adjustment is consistent with the adjustment recommended by Staff in Decision No. 69663.

Q. HOW WAS THE EMPLOYEE BENEFITS PRO FORMA ADJUSTMENT DETERMINED?

A. The total change in pension and OPEB expense is the difference between the Test Year expense and the 2008 level of that expense, as determined by our actuaries, Towers Perrin. As noted below, this resulted in a decrease to employee benefits expense.

Q. HOW DID YOU DETERMINE THE AMOUNT OF DECREASED BENEFITS COSTS PROPERLY ALLOCABLE TO APS' O&M?

A. An allocation factor was calculated and applied to the total change in benefit expenses. This allocation factor was determined by comparing APS' 2007 actual

O&M employee benefits to the total employee benefit costs for Pinnacle West. This results in an increase to pre-tax operating income of $2,660,000 (See Attachment JCL-15 and SFR Schedule C-2, page 8, column 24).

12. Normalize Income Tax Expense Including Synchronization of Interest

Q. WHAT METHODOLOGY DID YOU USE TO DETERMINE THE FEDERAL AND STATE INCOME TAX PRO FORMA ADJUSTMENT?

A. The Company used a "top down" approach in computing cost-of-service income tax expense. This calculation, which was also adopted in Decision No. 69663, used the statutory rate and estimated 2007 levels of various tax credits and other permanent tax items reflecting the Company's best estimate of on-going income tax expense. It also considers the deduction of interest expense synchronized to the end of the Test Year's Rate Base. The total federal and state income tax pro forma increases income tax expense by $4,829,000 (See Attachment JCL-16 and SFR Schedule C-2, page 9, column 25).

13. Annualize Property Tax Expense

Q. HAS APS PROPOSED AN ADJUSTMENT TO THE TEST YEAR AD VALOREM (PROPERTY) TAXES?

A. Yes. This adjustment reflects known and measurable December 31, 2007 plant values as calculated using the methods prescribed by the Arizona Revised Statutes (A.R.S.), the 2007 APS composite tax rate and the 2009 estimated State Equalization Assistance Property Tax Rate. This adjustment also takes into account the assessment ratio prescribed by A.R.S. § 42-15001(4) for 2009, which was revised by HB 2784 Chapter 258, (passed in the 2007 legislative session). Such assessment ratio will be in effect when the rates requested in this proceeding will likely become effective. This results in a reduction to pre-tax

operating income of $15,062,000 (See Attachment JCL-17 and SFR Schedule C-2, page 9, column 26).

Q. HOW WERE PROPERTY TAXES CALCULATED?

A. The property taxes reflect December 31, 2007 property values per the Arizona Department of Revenue and the 2007 tax year APS composite tax rate, which is calculated based on tax rates provided by the County Treasurer in each of the counties where APS has property. In addition, this proforma takes into account the increase in property tax rates in 2009 after the temporary suspension (suspended from 2006 through 2008) of the State Equalization Assistance Property Tax Rate ends. In April 2008, the Governor vetoed a bill that would have made that suspension permanent. Also, the electric generation land values reflect the changes made by HB 2657 Chapter 203, which passed during the 2007 legislative session.

14. Amortize Navajo Coal Reclamation Costs

Q. WHY IS THERE A PRO FORMA FOR NAVAJO COAL RECLAMATION?

A. Much like the pro forma for Four Corners Coal Reclamation which has routinely been included in rate filings, APS, as a Participant Owner of the Navajo Generating Station, is under contract with Peabody Coal Company until April 30, 2011 (with option to extend to April 30, 2026), to receive coal for the Navajo Generating Station. APS expects to be responsible for its share of final reclamation costs based on its share of coal purchases from Peabody.

Q. WHAT IS THE AMOUNT OF THE PRO FORMA ADJUSTMENT?

A. The pro forma adjustment reflects the annual amortization of the Navajo Generating Station Coal Reclamation over the life of the coal contract

(4/30/2026) assuming APS exercises the right to extend the current contract, less expense recorded during the Test Year related to the accrual of the reclamation obligation. This results in a reduction to pre-tax operating income of $231,000 (See Attachment JCL-18 and SFR schedule C-2, page 9, column 27).

B. *Other Pro Formas Including Out-Of-Period Adjustments*

1. Annualize Workforce Reduction Savings

Q. DOES APS HAVE ANY PLANS TO REDUCE ITS WORKFORCE?

A. Yes. In 2008, APS plans to reduce its employee levels by approximately 100 positions through a non-voluntary severance program.

Q. HAS APS REFLECTED THE COSTS AND SAVINGS ASSOCIATED WITH THESE REDUCTIONS IN WORKFORCE?

A. Yes. The first year savings associated with the elimination of these positions will be approximately $10,400,000, of which approximately $7,500,000 will be a savings to APS O&M. The remainder will be a reduction to capitalized construction costs.

The cost associated with severing 100 positions through a non-voluntary severance program is approximately $4,700,000. Under GAAP, these expenses were charged to O&M in December 2007. For ratemaking purposes however, these expenses should be amortized over a 3-year period for a yearly expense of approximately $1,600,000. This matches the cost of the employee reductions with the on-going savings. Similar amortization was requested in the Company's 2003 rate filing, but was not litigated as the case resulted in a settlement of which was approved under Decision No. 67744. This results in a

net increase to pre-tax operating income of $10,649,000 (See attachment JCL-19 and SFR Schedule C-2, page 10, column 28).

Q. DIDN'T APS ALSO ANNOUNCE REDUCTIONS IN CONTRACT EMPLOYEES AND THE ELIMINATION OF VACANT POSITIONS?

A. Yes. The former were used to augment the Company's construction workforce and thus their elimination would impact post-Test Year capital construction costs but not O&M. The elimination of open positions would likewise not impact Test Year O&M because APS used only on-board employees to determine its adjustment to annualize payroll.

2. Normalize Customer Bad Debt Expense

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TITLED NORMALIZE CUSTOMER BAD DEBT EXPENSE?

A. Yes. This pro forma adjusts customer bad debt expense to a level reflective of final, proforma weather-normalized, customer annualized Test Year operating revenues, and the average percentage of actual account write-offs experienced in the latest twelve month period available (twelve months ended April 30, 2008). This results in a decrease to pre-tax operating income of $979,000 (See attachment JCL-20 and SFR Schedule C-2, page 10, column 29).

3. Miscellaneous Out-of-Period Adjustments

Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TITLED MISCELLANEOUS OUT-OF-PERIOD ADJUSTMENTS?

A. Yes. In any chosen test year, there are bound to be some items recorded in the test year that relate to periods other than the test year, or conversely, items recorded in other time periods that correctly belong in the test year. This adjustment, for the sake of simplicity, combines several smaller entries that fit this description. They are shown in aggregate in the pro forma (see Attachment

JCL-21 and SFR Schedule C-2, page 10, column 30). This results in an increase to pre-tax operating income of $4,268,000.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDED 12/31/2007
(Thousands of Dollars)

Line No.	Function	PLANT ACCOUNT	DESCRIPTION	RCN (A)	Condition Percent (B)	RCND (C)	Line No.
1.	INTANGIBLES	301	Organization	$ -	0.00%	$ -	1.
2.		302	Franchises and consents	3,311	81.46%	2,697	2.
3.		303	Miscellaneous intangible plant	321,661	29.58%	95,147	3.
4.			SUBTOTAL	324,972		97,844	4.
5.	PRODUCTION	310	Land and Land Rights	3,306	100.00%	3,306	5.
6.		310	Limit Term Land Rights	64	26.06%	17	6.
7.		311	Structures and improvements	304,547	43.61%	132,813	7.
8.		312	Boiler plant equipment	2,189,214	38.80%	849,415	8.
9.		314	Turbogenerator units	660,493	46.11%	304,553	9.
10.		315	Accessory electric equipment	522,452	38.20%	199,577	10.
11.		316	Miscellaneous power plant equip.	126,156	52.64%	66,409	11.
12.		320	Land and land rights	3,501	100.00%	3,501	12.
13.		321	Structures and improvements	1,104,869	48.52%	536,082	13.
14.		322	Reactor plant equipment	1,800,853	50.07%	901,687	14.
15.		323	Turbogenerator units	613,415	49.47%	303,456	15.
16.		324	Accessory electric equipment	681,283	42.96%	292,679	16.
17.		325	Misc power plant equip	235,040	48.11%	113,078	17.
18.		330	Limit Term Land Rights	-	0.00%	-	18.
19.		331	Structures and improvements	-	0.00%	-	19.
20.		332	Reservoirs, dams, and waterways	-	0.00%	-	20.
21.		333	Water wheels, turbines and generators	-	0.00%	-	21.
22.		334	Accessory electric equipment	-	0.00%	-	22.
23.		335	Miscellaneous power plant equip.	-	0.00%	-	23.
24.		336	Roads, railroads and bridges	-	0.00%	-	24.
25.		340	Land and land rights	910	100.00%	910	25.
26.		341	Structures and improvements	84,978	72.76%	61,830	26.
27.		342	Fuel holders, products, and accessories	64,641	61.82%	39,961	27.
28.		343	Prime movers	825,951	70.85%	585,186	28.
29.		344	Generators	690,684	79.93%	552,064	29.
30.		345	Accessory electric equipment	146,492	67.90%	99,468	30.
31.		346	Miscellaneous power plant equip.	14,842	50.21%	7,452	31.
32.			SUBTOTAL	10,073,691		5,053,444	32.
33.	TRANSMISSION	350	Land and land rights	54,142	100.00%	54,142	33.
34.		350	Limit Term Land Rights	25,324	55.07%	13,946	34.
35.		352	Structures and improvements	71,122	57.04%	40,568	35.
36.		353	Station equipment	1,322,028	75.22%	994,429	36.
37.		354	Towers and fixtures	348,366	36.34%	126,596	37.
38.		355	Poles and fixtures	466,347	73.44%	342,485	38.
39.		356	Overhead conductors and devices	951,998	63.68%	606,232	39.
40.		357	Underground conduit	33,615	69.76%	23,450	40.
41.		358	Underground conductors and devices	58,495	59.59%	34,857	41.
42.			SUBTOTAL	3,331,437		2,236,705	42.
43.	DISTRIBUTION	360	Land and land rights	43,637	100.00%	43,637	43.
44.		360	Limit Term Land Rights	2,276	91.44%	2,081	44.
45.		361	Structures and improvements	68,398	62.39%	42,674	45.
46.		362	Station equipment	575,249	81.64%	469,633	46.
47.		364	Poles, towers, and fixtures	711,463	74.06%	526,909	47.
48.		365	Overhead conductors and devices	562,028	83.18%	467,495	48.
49.		366	Underground conduit	805,164	91.78%	738,980	49.
50.		367	Underground conductors and devices	2,044,622	69.71%	1,425,306	50.
51.		368	Line transformers	1,196,676	55.76%	667,267	51.
52.		369	Services	475,414	57.49%	273,316	52.
53.		370	Meters	257,507	83.78%	215,739	53.
54.		371	Installations on customers' premises	79,620	83.06%	66,132	54.
55.		373	Street lighting and signal systems	139,726	51.95%	72,588	55.
56.			SUBTOTAL	6,961,780		5,011,757	56.

ARIZONA PUBLIC SERVICE COMPANY
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDED 12/31/2007
(Thousands of Dollars)

57.	GENERAL	389	Land and land rights	13,191	100.00%	13,191	57.
58.		390	Structures and improvements	245,179	56.45%	138,404	58.
59.		390	Structures and improvements - Lease	123	57.99%	71	59.
60.		391	Office furniture and equipment	154,441	55.53%	85,761	60.
61.		391	Capitalized Lease-Computer Equipment	-	0.00%	-	61.
62.		392	Transportation equipment	35,247	12.95%	4,564	62.
63.		392	Capitalized Lease-Transportation Equip.	8,607	49.40%	4,252	63.
64.		393	Stores equipment	6,179	8.05%	497	64.
65.		394	Tools, shop and garage equipment	27,966	62.59%	17,504	65.
66.		395	Laboratory equipment	3,725	51.72%	1,927	66.
67.		396	Power operated equipment	21,149	25.75%	5,446	67.
68.		397	Communication equipment	173,787	68.31%	118,714	68.
69.		398	Miscellaneous equipment	12,117	25.39%	3,077	69.
70.			SUBTOTAL	701,711		393,408	70.
71.		TOTAL PLANT (a)		$ 21,393,591		$ 12,793,158	71.

Supporting Schedules:
RCND Study

Recap Schedules:
(a) B-3

ARIZONA PUBLIC SERVICE COMPANY
RCN by Major Plant Accounts
With Contribution In Aid of Construction Identified by Function
Test year Ended 12/31/07
(Thousands of Dollars)

Line No.	Description	Gross Amount (a)	Contributions In Aid Of Construction (b)	Net Amount (c)
1.	Intangible Plant	$ 324,972	$ -	$ 324,972
2.	Production Plant	10,196,439	(122,746)	10,073,693
3.	Transmission Plant	3,614,141	(282,703)	3,331,438
4.	Distribution Plant	7,228,998	(267,220)	6,961,778
5.	General Plant	699,511	(6,531)	692,980
6.	Utility Plant In Service*	$ 22,064,061	(679,200)	$ 21,384,861
7.			Capital Leases	8,730
8.	Utility Plant In Service including Capital Leases			$ 21,393,591

* Excludes Capital Leases

ARIZONA PUBLIC SERVICE COMPANY
Computation of Working Capital
Test Year Ended 12/30/07
(Dollars in Thousands)

Line No.	Description	Amount	
1.	Working Capital - Operations	$ (103,403)	
2.	Materials and Supplies (1)	149,759	a
3.	Fuel - Coal and Oil	27,792	b
4.	Fuel - Nuclear, Net	69,271	c
5.	Prepayments	15,407	
6.	Special Deposits & Working Funds	226	
7.	Total Working Capital Allowance	$ 159,052	
	a+b+c=	246,822	

Note 1: APS Materials and Supplies include FERC 154 &156

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 14
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Annualize Spent Fuel Storage Costs**
Adjustment to Test Year operations to annualize spent fuel storage costs per Decision No. 69663.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Expenses**	
4.	Fuel Expense	1,289
5.	Total Expenses	$ 1,289
6.	**Operating Income (before income tax)**	**$ (1,289)**
7.	Current Income Tax Rate - 39.36%	(507)
8.	**Operating Income After Tax**	**$ (782)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 15
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Annualize Four Corners Coal Reclamation Costs**
Adjustment to Test Year operations to annualize coal reclamation costs for the Four Corners Power Plant per Decision No. 69663.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Expenses**	
4.	Fuel Expense	334
5.	Total Expenses	$ 334
6.	**Operating Income (before income tax)**	**$ (334)**
7.	Current Income Tax Rate - 39.36%	(131)
8.	**Operating Income After Tax**	**$ (203)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 16
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Annualize Bark Beetle Remediation Costs**
Adjustment to Test Year operations to annualize the amortization of deferred bark beetle costs over a three year period as authorized in Decision No. 69663.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expenses	1,918
5.	Maintenance	-
6.	Total Expenses	$ 1,918
7.	**Operating Income (before income tax)**	**$ (1,918)**
8.	Current Income Tax Rate - 39.36%	(755)
9.	**Operating Income After Tax**	**$ (1,163)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 17
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Annualize Depreciation and Amortization per Decision No. 69663**
Adjustment to Test Year operations to annualize depreciation and amortization expense in accordance with Decision No. 69663.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Depreciation	10,691
5.	Total Expenses	$ 10,691
6.	**Operating Income (before income tax)**	**$ (10,691)**
7.	Current Income Tax Rate - 39.36%	(4,208)
8.	**Operating Income After Tax**	**$ (6,483)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 18
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Remove Test Year Surcharges**
Adjustment to Test Year operations to remove the Environmental Portfolio Standard, Competition Rules Compliance Charge, and Regulatory Assessment surcharges from both operating revenues and operating expenses.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Revenues in Base Rates	$ 3,000
3.	Surcharge Revenue	(23,783)
4.	Other Electric Revenue	-
5.	Total Electric Operating Revenues	$ (20,783)
6.	**Other Operating Expenses**	
7.	Operations Excluding Fuel Expenses	(19,347)
8.	Maintenance	-
9.	Total Expenses	$ (19,347)
10.	**Operating Income (before income tax)**	**$ (1,436)**
11.	Current Income Tax Rate - 39.36%	(565)
12.	**Operating Income After Tax**	**$ (871)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 19
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Annualize Sundance Overhaul Maintenance Expense**
Adjustment to Test Year operations to annualize overhaul maintenance expense for the Sundance Units in accordance with Decision No. 69663.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expenses	805
5.	Maintenance Expenses	-
6.	Total Expenses	$ 805
7.	**Operating Income (before income tax)**	**$ (805)**
8.	Current Income Tax Rate - 39.36%	(317)
9.	**Operating Income After Tax**	**$ (488)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 2, column 6
Total Company
(Thousands of Dollars)

Proforma Adjustment: **West Phoenix Unit 4 Regulatory Disallowance [Rate Base]**
Adjustment to reduce Test Year rate base for the regulatory disallowance for West Phoenix Unit 4 as required in Decision Nos. 67744 and 69663.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ (13,833)
2.	Less: Accumulated Depreciation and Amortization	(2,649)
3.	Net Utility Plant in Service	$ (11,184)
4.	Less: Total Deductions	(1,120)
5.	Total Additions	-
6.	**Total Rate Base**	**$ (10,064)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 20
Total Company
(Thousands of Dollars)

Proforma Adjustment: **West Phoenix Unit 4 Regulatory Disallowance [Operating Income]**
Adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant as required by Decision Nos. 67744 and 69663. Proforma adjusted as shown on Schedule B-2, page 2, column 6.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Depreciation	(329)
5.	Total Expenses	$ (329)
6.	**Operating Income (before income tax)**	**$ 329**
7.	**Interest Expense**	**(268)**
8.	Taxable Income	**$ 597**
9.	Current Income Tax Rate - 39.36%	235
10.	**Operating Income After Tax**	**$ 94**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 21
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Interest Expense on Customer Deposits**
Adjustment to Test Year operations to reflect the operating income impact of interest expense on customer deposits using January 2008 interest rates.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expenses	2,261
5.	Maintenance	-
6.	Total Expenses	$ 2,261
7.	**Operating Income (before income tax)**	**$ (2,261)**
8.	Current Income Tax Rate - 39.36%	(890)
9.	**Operating Income After Tax**	**$ (1,371)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 22
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Depreciation Expense - 2007 Depreciation Study**
Adjustment to Test Year operations to reflect depreciaton expense based on the 2007 depreciation study.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Depreciation	(9,076)
5.	Total Expenses	$ (9,076)
6.	**Operating Income (before income tax)**	**$ 9,076**
7.	Current Income Tax Rate - 39.36%	3,572
8.	**Operating Income After Tax**	**$ 5,504**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 23
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Annualize Payroll**
Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax, and non-retirement benefit expenses to March 2008 employees levels, March 2008 wage levels for Performance Review Employees and March 2009 wage levels for Union employees.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expenses	15,458
5.	Maintenance	5,380
6.	Total Expenses	$ 20,838
7.	**Operating Income (before income tax)**	**$ (20,838)**
8.	Current Income Tax Rate - 39.36%	(8,202)
9.	**Operating Income After Tax**	**$ (12,636)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 24
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Normalize Employee Benefits**
Adjustment to test year operations to reflect the current December 2007 actuarial valuation of retirement program expenses.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expenses	(2,660)
5.	Maintenance	
6.	Total Expenses	$ (2,660)
7.	**Operating Income (before income tax)**	**$ 2,660**
8.	Current Income Tax Rate - 39.36%	1,047
9.	**Operating Income After Tax**	**$ 1,613**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 25
Total Company
(Thousands of Dollars)

Pro Forma Adjusment: Normalize Income Tax Expense/Interest Synchronization
Adjustment to Test Year operations for top down income tax true-ups (including generation production income tax deduction, 2007 on-going tax credits and other permanent tax items and income tax/interest synchronization) consistent with Decision No. 69663 using the 12/31/2007 capital structure and cost of long-term debt.

Line No.	Description		Total Company Amount
1.	Operating Income	$	-
2.	Net Deductions		-
3.	Interest		(31,207)
4.	**Taxable Income**	**$**	**31,207**
5.	**Income Tax**	**$**	**4,829**
6.	Deferred Tax		-
7.	**Net Income**	**$**	**(4,829)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 26
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Annualize Property Tax Expense**
Adjustment to Test Year operations to annualize property taxes calculated using the most recent tax assessment ratio and tax rate.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Other Taxes	15,062
5.	Total Expenses	$ 15,062
6.	**Operating Income (before income tax)**	**$ (15,062)**
7.	Current Income Tax Rate - 39.36%	(5,928)
8.	**Operating Income After Tax**	**$ (9,134)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 27
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Amortize Navajo Coal Reclamation Costs**
Adjustment to Test Year operations to reflect the annualized amortization of the Regulatory Asset which established APS' share of the final coal reclamation and settled tail (post mining activity) costs for the Navajo Generating Station dedicated mine.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Expenses**	
4.	Fuel Expense	231
5.	Total Expenses	$ 231
6.	**Operating Income (before income tax)**	**$ (231)**
7.	Current Income Tax Rate - 39.36%	(91)
8.	**Operating Income After Tax**	**$ (140)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 28
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Annualize Workforce Reduction Savings**
Adjustment made to Test Year operations for the savings, net of severance costs, associated with the expected workforce reduction of 100 employees in 2008.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Other Operating Expenses**	
4.	Operations Excluding Fuel Expenses	(10,649)
5.	Maintenance	-
6.	Total Expenses	$ (10,649)
7.	**Operating Income (before income tax)**	**$ 10,649**
8.	Current Income Tax Rate - 39.36%	4,191
9.	**Operating Income After Tax**	**$ 6,458**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 29
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Normalize Customer Bad Debt Expense**
Adjustment to Test Year operations to reflect a normalized level of bad debt expense.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Expenses**	
4.	Operations & Maintenance	979
5.	A&G	-
6.	Total Expenses	$ 979
7.	**Operating Income (before income tax)**	**$ (979)**
8.	Current Income Tax Rate - 39.36%	(385)
9.	**Operating Income After Tax**	**$ (594)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 30
Total Company
(Thousands of Dollars)

Proforma Adjustment: **Miscellaneous Out-of-Period Adjustments**
Adjustment to Test Year operations to eliminate non-recurring and out-of-period expenses.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Expenses**	
4.	Operations & Maintenance	(4,268)
5.	A&G	-
6.	Total Expenses	$ (4,268)
7.	**Operating Income (before income tax)**	**$ 4,268**
8.	Current Income Tax Rate - 39.36%	1,680
9.	**Operating Income After Tax**	**$ 2,588**

Ronald E. White

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E–01345A–08–0172

June 2008

TABLE OF CONTENTS

I. QUALIFICATIONS 1

II. PURPOSE OF TESTIMONY 3

III. DEVELOPMENT OF DEPRECIATION RATES 3

IV. 2008 DEPRECIATION RATE STUDY 7

APPENDIX A – PROFESSIONAL QUALIFICATIONS

ATTACHMENT:

REW–1: 2008 DEPRECIATION RATE STUDY

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am Chairman and a Senior Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member

of the American Economic Association, the Financial Management Association, the Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over thirty jurisdictions, including several appearances in Arizona. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is attached as Appendix A.

II. PURPOSE OF TESTIMONY

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

A. Foster Associates was engaged by Arizona Public Service Company (APS or Company) to conduct a 2008 depreciation rate study for plant subject to the jurisdiction of the Arizona Corporation Commission (ACC). The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates. Depreciation rates currently used by APS were approved by the ACC in Docket No. E–01345A–05–0816 et al. (Decision No. 69663, dated June 28, 2007).

III. DEVELOPMENT OF DEPRECIATION RATES

Q. WOULD YOU PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life system) of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regula-

tion, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. It can be shown that given the same financing requirements and the same dividend payout ratio, an increase in internal cash generation will accelerate per–share growth in earnings, dividends, and book value over the business life of a firm. Financial theory provides that the marginal cost of external financing will be reduced by these enhanced measurements of financial performance. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. WHAT ARE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and removal expense. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors which should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements

that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

IV. 2008 Depreciation Rate Study

Q. DID APS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2008 DEPRECIATION STUDY?

A. Yes, they did. Service life statistics estimated in this study were derived from plant accounting transactions recorded over the period 1971 through 2007. Detailed accounting transactions were extracted from the CPR (Continuing Property Record) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

Work on the database used in the 2008 study was initiated in contemplation of a 2005 depreciation rate study. Completion of the database was suspended, however when time constraints necessitated assembling a 2005 technical update in lieu of a full study. Data used in the 2005 update and subsequent 2007 technical update were limited to age distributions of surviving plant at December 31, 2004 and December 31, 2006, respectively. Development of the full database was completed for conducting the 2008 study.

Data initially provided to Foster Associates were in an electronic format containing plant and reserve activity over the period 1971–2004 and age distributions of surviving plant at December 31, 2004. Age distributions at December 31, 2006 were subsequently provided to conduct the 2007 technical update.

The 2007 database was updated for the current study by appending additional plant and net salvage transactions for activity year 2005–2007 and age distributions

of surviving plant at December 31, 2007. The accuracy and completeness of the assembled database was verified for activity years 1993 through 2007 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Age distributions of surviving plant at December 31, 2007 were reconciled to the CPR.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR APS PLANT AND EQUIPMENT?

A. Yes, we did. As discussed in Attachment REW–1, all plant accounts were analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function can be expressed as a survivorship function, which is numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category. Plant accounts classified in Steam, Nuclear and Other Production were identified by unit and treated as life–span categories in the 2008 study.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR APS PLANT AND EQUIPMENT?

A. Yes, we did. A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2008 study for transmission, distribution and general plant categories to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates for all depreciable plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate.

Future net salvage rates for steam production facilities were previously adjusted in the 2005 update for estimated terminal dismantlement costs reflecting costs per kW derived in dismantling studies conducted in 2002 for the Navajo and Four Corners generating stations. Pending the availability of updated dismantling studies, this treatment (as approved in Docket No. E–01345A–05–0816 et al.) was retained in the 2008 study.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes, we did. Statement C of Attachment REW–1 provides a comparison of APS recorded, computed and redistributed reserves at December 31, 2007. The recorded reserve was $3,843,430,272 or 38.7 percent of the depreciable plant investment. The corresponding computed reserve is $3,255,093,815 or 32.8 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $588,336,456 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study. Statement D of Attachment REW–1 provides an estimate of the investment and net salvage components of the rebalanced reserves.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES FOR APS?

A. Yes, we are. Depreciation rates adopted in Docket No. E–01345A–03–0437 were derived from rebalanced reserves obtained from a set of parameters different from those used in the formulation of the settled remaining–life accrual rates. Reserve imbalances amortized in the settled rates were therefore inconsistent with the realigned depreciation reserves. Accordingly, reserves were rebalanced in the 2005 update and

approved in Docket No. E–01345A–05–0816 et al. The rebalancing of reserves undertaken in the 2008 update will reestablish consistency between measured reserve imbalances at December 31, 2007 and the parameters used in the formulation of the proposed remaining–life accrual rates.

A redistribution of reserves is also needed to eliminate reserve imbalances identified by the initialization of amortization accounting proposed for various general plant accounts and two distribution meter accounts. Amortization periods proposed for these accounts were used to derive theoretical reserves that will replace the recorded reserves and permit a uniform treatment of both embedded plant and future additions. Plant older than the proposed amortization period will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserves (net of amortizable accounts) to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Q. WOULD YOU PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED BY THE COMMISSION FOR APS?

A. Current depreciation rates were developed for each primary account using a depreciation system composed of the straight–line method, broad group procedure, remaining–life technique.

The formulation of an account accrual rate using the currently approved depreciation system is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where both the computed reserve and the recorded reserve are expressed as ratios to the plant in service.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM FOR APS?

A. Yes, we are. Depreciation rates recommended in the 2008 study for all depreciable plant categories were derived from a system composed of the straight–line method, vintage group procedure, remaining–life technique. This change in procedure from broad group to vintage group is recommended by Foster Associates to more nearly achieve the goals and objectives of depreciation accounting.

Unlike the broad group procedure in which each vintage is estimated to have the same average service life, consideration is given to the realized life of each vintage when average service lives and remaining lives are derived using the vintage group procedure. The vintage group procedure distinguishes average service lives among vintages and composite life statistics are computed for each plant account. The formulation of an account accrual rate using the straight–line method, vintage group procedure, remaining–life technique is identical to the broad group procedure. Additionally, Foster Associates is recommending amortization accounting for selected general support asset categories in which the unit cost of equipment is small in relation to the cost of maintaining detailed accounting records and for two distribution metering accounts.

Q. WOULD YOU PLEASE DESCRIBE THE PLANT CATEGORIES FOR WHICH AMORTIZATION ACCOUNTING IS RECOMMENDED?

A. Depreciation accounting would be replaced with amortization accounting for the genera plant categories summarized in Table 2 below.

Account Number	Description	Amortization Period
A	B	C
391.FE	Office Furn. and Equip. - Furniture	20 yrs.
393.00	Stores Equipment	20 yrs.
394.00	Tools, Shop and Garage Equipment	20 yrs.
395.00	Laboratory Equipment	20 yrs.
398.00	Miscellaneous Equipment	24 yrs.

Table 2. Proposed Amortization Accounts

Amortization accounting is also recommended for Account 370.01 (Meters – Electronic) and Account 370.02 (Meters – Electromechanical). APS has committed to a program of replacing electronic and electromechanical meters with AMI (Advanced Metering Infrastructure) meters by 2012. Accordingly, a 5–year amortization period is recommended for Accounts 370.01 and 370.02. The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology. Reserve imbalances associated with the proposed meter amortization accounts were distributed to the remaining depreciable accounts in the Distribution plant function.

Q. HOW DOES AMORTIZATION ACCOUNTING DIFFER FROM DEPRECIATION ACCOUNTING?

A. Unlike depreciation accounting in which a depreciation rate is applied to the cost of plant and equipment remaining in service regardless of the age of the property, amortization accounting ceases depreciation on all assets older than the amortization period. Although plant may physically remain in service beyond the end of the amortization period (or have been removed from service before the end of the period), no attempt is made to track the physical disposition of each asset. Vintages of plant achieving an age equal to the amortization period are retired from service, regardless of the physical disposition of the assets. Salvage or removal expense realized on am-

ortizable assets is netted against current–year vintage additions.

It is the opinion of Foster Associates that the adoption of amortization accounting proposed in this study is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Adoption of amortization accounting for the general plant categories will relieve APS of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets. Amortization of the metering accounts will eliminate the need further asset tracking of these two closed–ended plant accounts.

Q. WOULD YOU PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS FOSTER ASSOCIATES IS RECOMMENDING FOR APS IN THE 2008 STUDY?

A. Table 3 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended in the 2008 depreciation study.

Function	Accrual Rate			2008 Annualized Accrual		
	Present	Proposed	Diff.	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.86%	3.51%	-0.35%	$57,991,639	$52,743,069	($5,248,570)
Nuclear Production	2.80%	2.78%	-0.02%	68,608,141	68,160,962	(447,179)
Other Production	2.59%	3.02%	0.43%	34,229,815	39,880,095	5,650,280
Transmission	1.38%	2.26%	0.88%	1,139,490	1,865,917	726,427
Distribution	2.50%	2.37%	-0.13%	103,532,446	97,969,879	(5,562,567)
General Plant	5.99%	4.99%	-1.00%	25,358,257	21,114,220	(4,244,037)
Total	2.93%	2.84%	-0.09%	$290,859,788	$281,734,142	($9,125,646)

Table 3. Present and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.84 percent. Depreciation expense is currently accrued at rates that composite to 2.93 percent. The recommended change in the composite depreciation rate is, therefore, a decrease of 0.09 percentage points.

A continued application of current rates would provide annualized depreciation expense of $290,859,788 compared with an annualized expense of $281,734,142 using the rates developed in this study. The proposed 2008 expense decrease is $9,125,646. The computed change in annualized accruals includes a reduction of $24,256,491 attributable to an amortization of a $588,336,456 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2008 study.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Foster Associates Inc.
17595 S. Tamiami Trail
Suite 212
Fort Myers, FL 33908

Phone (239) 267-1600
Fax (239) 267-5030
E-mail r.white@fosterfm.com

Ronald E. White, Ph.D.

Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

2007 - Present Foster Associates, Inc.
Chairman

1996 - 2007 Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Testifying Witness

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04--0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone

Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New

Jersey Natural Gas Company; testimony concerning depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper

depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Activities

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291

(JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, *et. al.* File No. 394126; testimony concerning depreciation and engineering economics.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Speaker

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property

Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and

the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Attachment REW–1

2008 Depreciation Rate Study

Arizona Public Service Company

Prepared by
Foster Associates, Inc.

FOSTER ASSOCIATES INCORPORATED

CONTENTS

EXECUTIVE SUMMARY — SECTION I

INTRODUCTION 1

SCOPE OF STUDY 2

DEPRECIATION SYSTEM 2

PROPOSED DEPRECIATION RATES 4

COMPANY PROFILE — SECTION II

GENERAL 6

GENERATING RESOURCES 6

TRANSMISSION AND DISTRIBUTION FACILITIES 7

STUDY PROCEDURE — SECTION III

INTRODUCTION 8

SCOPE 8

DATA COLLECTION 8

LIFE ANALYSIS AND ESTIMATION 10

NET SALVAGE ANALYSIS 12

DEPRECIATION RESERVE ANALYSIS 13

DEVELOPMENT OF ACCRUAL RATES 15

STATEMENTS — SECTION IV

INTRODUCTION 17

STATEMENT A – COMPONENT ACCRUAL RATES 19

STATEMENT B – COMPONENT ACCRUALS 26

STATEMENT C – DEPRECIATION RESERVE SUMMARY 36

STATEMENT D – DEPRECIATION RESERVE COMPONENTS 47

STATEMENT E – AVERAGE NET SALVAGE 59

STATEMENT F – FUTURE NET SALVAGE 68

STATEMENT G – DISMANTLEMENT COSTS 72

STATEMENT H – PRESENT AND PROPOSED PARAMETERS 73

ANALYSIS — SECTION V

INTRODUCTION 85

SCHEDULE A – GENERATION ARRANGEMENT 85

SCHEDULE B – AGE DISTRIBUTION 86

SCHEDULE C – PLANT HISTORY 87

SCHEDULE D – ACTUARIAL LIFE ANALYSIS 87

SCHEDULE E – GRAPHICS ANALYSIS 88
SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS 88

DISTRIBUTION

ACCOUNT 367.00 – UNDERGROUND CONDUCTORS AND DEVICES

SCHEDULE A – GENERATION ARRANGEMENT 89
SCHEDULE B – AGE DISTRIBUTION 91
SCHEDULE C – PLANT HISTORY 93
SCHEDULE D – ACTUARIAL LIFE ANALYSIS 95
SCHEDULE E – GRAPHICS ANALYSIS 98
SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS (DISTRIBUTION) 101

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for utility plant owned and operated by Arizona Public Service Company (APS). The report contains recommended 2008 depreciation rates and parameters for: a) steam and other production assets; b) nuclear assets; and c) electric transmission, distribution and general plant categories. Work on the study commenced in April 2008 and progressed through May, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers, Florida office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by APS were approved by the Arizona Corporation Commission (ACC) in Docket No. E–01345A–05–0816 et al. (Decision No. 69663, dated June 28, 2007). Parameters (*i.e.*, projection curves, projection lives and future net salvage rates used to derive the approved rates were accepted by the ACC pursuant to a settlement agreement in Docket No. E–01345A–03–0437 (Decision No. 67744, dated April 7, 2005).[1]

The principal findings and recommendations of the 2008 Depreciation Rate Study are summarized in the Section IV of this report. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain

[1] A 2007 Technical Update of depreciation rates was filed with the ACC on March 24, 2008 in Docket No. E01345A–08–0172. Acceptance of the application is currently pending receipt of updated financial schedules, testimony and other data through December 31, 2007.

weighted–average net salvage rates. Statement F provides a computation of the estimated future net salvage rate for steam production facilities. Statement G contains the computation of terminal dismantlement costs for steam production facilities. Statement H provides a comparative summary of present and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains present and proposed statistics including average service life, average remaining life, and average net salvage rates.

Scope of Study

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Field visits and discussions with APS operations and plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

Depreciation System

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

APS is currently using a depreciation system composed of the straight–line method, broad group procedure, remaining–life technique for all plant categories. The system was accepted by the ACC in Docket No. E–01345A–03–0437 without comment as to its appropriateness or a consideration of alternative systems. Depreciation rates recommended in the 2008 study for all depreciable plant categories were derived from a system composed of the straight–line method, vintage group procedure, remaining–life technique. This change in procedure from broad group to vintage group is recommended by Foster Associates to more nearly achieve the goals and objectives of depreciation accounting.

The matching and expense recognition principles of accounting provide that

the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting can be more nearly achieved using the vintage group procedure combined with the remaining–life technique.

Unlike the broad group procedure in which each vintage is estimated to have the same average service life, the vintage group procedure distinguishes average service lives among vintages and provides cost apportionment over the estimated weighted–average remaining life or average life of a rate category.

The level of asset grouping identified in the broad group procedure is the total plant in service from all vintages in an account. Each vintage is estimated to have the same average service life. It is unlikely, therefore, that compensating deviations (*i.e.*, over and underestimates of average service life) will be created among vintages to achieve cost allocation over the average service life of each vintage.

The level of asset grouping identified in the vintage group procedure is the plant in service from each vintage. The average service life (or remaining life) is estimated independently for each vintage and composite life statistics are computed for each plant account. It is more likely that compensating deviations will be created with a vintage group procedure than with a broad group procedure.

In addition to adjustments to depreciation rates, Foster Associates is recommending amortization accounting for selected general support asset categories in which the unit cost of equipment is small in relation to the cost of maintaining detailed accounting records. Depreciation accounting would be replaced with amortization accounting for the asset categories summarized in Table 1 below.

Account Number	Description	Amortization Period
A	B	C
391.FE	Office Furn. and Equip. - Furniture	20 yrs.
393.00	Stores Equipment	20 yrs.
394.00	Tools, Shop and Garage Equipment	20 yrs.
395.00	Laboratory Equipment	20 yrs.
398.00	Miscellaneous Equipment	24 yrs.

Table 1. Proposed Amortization Accounts

Amortization periods recommended by Foster Associates for these accounts were used to drive theoretical reserves that will replace the recorded reserves and permit a uniform treatment of both embedded plant and future additions. Plant older than the proposed amortization period will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortiza-

tion period. Reserve imbalances created by the recommended amortization periods were eliminated by a systematic redistribution of recorded reserves. Reserve imbalances for the proposed amortization accounts were distributed to the remaining depreciable accounts in the General plant function. Net salvage realized in the future will be netted against current–year vintage additions.

Amortization accounting is also recommended for Account 370.01 (Meters – Electronic) and Account 370.02 (Meters – Electromechanical). APS has committed to a program of replacing electronic and electromechanical meters with AMI (Advanced Metering Infrastructure) meters by 2012. Accordingly, a 5–year amortization period is recommended for Accounts 370.01 and 370.02. The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology. Reserve imbalances associated with the proposed meter amortization accounts were distributed to the remaining depreciable accounts in the Distribution plant function.

PROPOSED DEPRECIATION RATES

Table 2 below provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation system recommended in the 2008 study for APS.

Function	Accrual Rate			2008 Annualized Accrual		
	Present	Proposed	Diff.	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.86%	3.51%	-0.35%	$57,991,639	$52,743,069	($5,248,570)
Nuclear Production	2.80%	2.78%	-0.02%	68,608,141	68,160,962	(447,179)
Other Production	2.59%	3.02%	0.43%	34,229,815	39,880,095	5,650,280
Transmission	1.38%	2.26%	0.88%	1,139,490	1,865,917	726,427
Distribution	2.50%	2.37%	-0.13%	103,532,446	97,969,879	(5,562,567)
General Plant	5.99%	4.99%	-1.00%	25,358,257	21,114,220	(4,244,037)
Total	2.93%	2.84%	-0.09%	$290,859,788	$281,734,142	($9,125,646)

Table 2. Present and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.84 percent. Depreciation expense is currently accrued at rates that composite to 2.93 percent. The recommended change in the composite depreciation rate is, therefore, a decrease of 0.09 percentage points.

A continued application of current rates would provide annualized depreciation expense of $290,859,788 compared with an annualized expense of $281,734,142 using the rates developed in this study. The proposed 2008 expense decrease is $9,125,646. The computed change in annualized accruals includes a

reduction of $24,256,491 attributable to an amortization of a $588,336,456 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2008 study.

Of the 173 plant accounts included in the 2008 study, Foster Associates is recommending rate reductions for 98 accounts and rate increases for 75 accounts.

COMPANY PROFILE

GENERAL

Arizona Public Service Company is the largest subsidiary of Pinnacle West. APS serves more than one million customers in 11 of Arizona's 15 counties.

Incorporated in 1920 under the laws of the state of Arizona, APS employs more than 6,000 employees, including employees at jointly–owned generating facilities for which APS serves as the generating facility manager. In addition to the Palo Verde Nuclear Generating Station, APS owns and operates seven natural–gas plants, two coal–fired plants, and an increasing array of renewable energy power generation.

APS has built an infrastructure consisting of more than 30,000 miles of transmission and distribution lines and 400 substations.

GENERATING RESOURCES

The Palo Verde Nuclear Generating Station is owned by a consortium of seven utilities in the Southwest and is operated by APS. Its three units are capable of generating nearly 4,000 megawatts of electricity. APS owns 29.1 percent of the plant.

The five–unit, 2040 megawatt Four Corners Power Plant, located on the Navajo Indian Reservation is owned by APS and five other utilities in the Southwest. The plant is operated by APS and fueled by low–sulfur coal from the nearby Navajo mine.

The 995 megawatt Cholla Power Plant is located in northeastern Arizona. APS operates the plant and owns Units 1, 2 and 3, which are capable of producing 615 megawatts of electricity. PacifiCorp owns the 380 megawatt Unit 4. Cholla is fueled by coal from the McKinley Mine in New Mexico.

The Navajo Power Plant is located in northern Arizona on the Navajo Indian Reservation near Page. The plant's three 750 megawatt coal–fueled, steam–electric generating units are owned by a partnership of five utility companies and the U.S. Bureau of Reclamation. APS owns 14 percent of the plant, which is operated by Salt River Project.

The Redhawk Power Station, which began operating in mid–2002, is comprised of two identical 530 megawatt natural gas–fueled combined–cycle units. The plant is owned and operated by APS.

The natural gas–fueled West Phoenix Power Plant has seven generating units, two combustion turbine units and five units that employ combined–cycle technology. Owned and operated by APS, West Phoenix generates about 1,000 megawatts of electricity.

Ocotillo is a natural gas–fueled Power Plant owned and operated by APS. Located

in Tempe, Arizona, the plant has two steam and two combustion turbine units that are capable of generating about 340 megawatts.

The natural gas–fueled Saguaro Power Plant, located north of Tucson, has two steam units and three combustion turbine units. APS owns and operates all five of the generating units that have a combined capacity of about 395 megawatts available to the APS system.

APS operates the natural gas–fueled Yucca Power Plant located near Yuma in southwestern Arizona. The Company owns four combustion turbine units that produce nearly 150 megawatts for APS customers.

Since 1996, APS has completed a number of solar projects around the state. The current capacity of their solar plants is about five megawatts.

Transmission and Distribution Facilities

APS' transmission facilities consist of approximately 5,759 pole miles of overhead lines and approximately 45 miles of underground lines, 5,535 miles of which are located in Arizona. APS shares ownership of some of its transmission facilities with other companies.

APS' distribution facilities consist of approximately 12,471 miles of overhead lines and approximately 16,210 miles of underground primary cable, all of which are located in Arizona.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of depreciation accruals and recorded depreciation reserves for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation rates used by APS for its steam, nuclear, other production, transmission, distribution and general plant categories. The proposed rates are subject to approval by the Arizona Corporation Commission.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2008 study for APS included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribu-

tion to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by APS provides aged transactions for all plant accounts.

Service life statistics estimated in this study were derived from plant accounting transactions recorded over the period 1971 through 2007. Detailed accounting transactions were extracted from the CPR system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

Work on the database used in the 2008 study was initiated in contemplation of a 2005 depreciation rate study. Completion of the database was suspended, however when time constraints necessitated assembling a 2005 technical update in lieu of a full study. Data used in the 2005 update and subsequent 2007 technical update were limited to age distributions of surviving plant at December 31, 2004 and December 31, 2006, respectively. Development of the full database was completed for conducting the 2008 study.

Data initially provided to Foster Associates were in an electronic format containing plant and reserve activity over the period 1971–2004 and age distributions of surviving plant at December 31, 2004. Age distributions at December 31, 2006 were subsequently provided to conduct the 2007 technical update.

The 2007 database was updated for the current study by appending additional plant and net salvage transactions for activity year 2005–2007 and age distributions of surviving plant at December 31, 2007. The accuracy and completeness of the assembled database was verified for activity years 1993 through 2007 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Age distributions of surviving plant at December 31, 2007 were reconciled to the CPR.

Reserve transactions recorded over the period 1980–2007 were used in the 2008 study to derive appropriate net salvage rates. Depreciation rates currently used by APS were derived without consideration of the distinction between aver-

age and future net salvage rates. Realized net salvage was blended with future net salvage estimates in the current study to derive average net salvage rates used in the computation of theoretical reserves.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2008 APS depreciation study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the

annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed in as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

The program also provides tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), the concept of retirement dispersion is interpreted differently for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All plant accounts classified in Steam, Nuclear and Other Production were identified by unit and treated as life–span categories in the 2008 study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimate of the net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a reasonable basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

Future net salvage rates for steam production facilities were previously adjusted in the 2005 update for estimated terminal dismantlement costs reflecting costs per kW derived in dismantling studies conducted in 2002 for the Navajo and Four Corners generating stations. Pending the availability of updated dismantling

studies, this treatment (as approved in Docket No. E–01345A–05–0816 et al.) was retained in the 2008 study. Statement G provides a computation of terminal dismantlement costs used in Statement F to derive future net salvage rates for steam production facilities. The distinction between average and future net salvage rates is shown in Statement E.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2008 study for transmission, distribution and general plant categories to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates for all depreciable plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of estimated average net salvage rates is shown in Statement E.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are

distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is appropriate for APS. Depreciation rates adopted in Docket No. E–01345A–03–0437 were derived from rebalanced reserves obtained from a set of parameters different from those used in the formulation of the settled remaining–life accrual rates. Reserve imbalances amortized in the settled rates were therefore inconsistent with the realigned depreciation reserves. Accordingly, reserves were rebalanced in the 2005 update and approved in Docket No. E–01345A–05–0816 et al. The rebalancing of reserves undertaken in the 2008 update will reestablish consistency between measured reserve imbalances at December 31, 2007 and the parameters used in the formulation of the proposed remaining–life accrual rates.

A redistribution of reserves is also needed to eliminate reserve imbalances identified by the initialization of amortization accounting proposed for various general plant accounts and two distribution meter accounts. Amortization periods proposed for these accounts were used to derive theoretical reserves that will replace the recorded reserves and permit a uniform treatment of both embedded plant and future additions. Plant older than the proposed amortization period will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. Depreciation reserves for amor-

tizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserves (net of amortizable accounts) to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of recorded, computed and redistributed reserves at December 31, 2007. The recorded reserve was $3,843,430,272 or 38.7 percent of the depreciable plant investment. The corresponding computed reserve is $3,255,093,815 or 32.8 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $588,336,456 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Statement D provides an estimate of the investment and net salvage components of the rebalanced reserves.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not alter the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be

used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2008 study were developed using a system composed of the straight–line method, vintage group procedure, remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique combined with an amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that this system will remain appropriate for APS, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that adoption of amortization accounting as proposed in this study for selected general support asset accounts and two distribution meter accounts is consistent with the goals and objectives of depreciation derived from the matching and expense recognition principles of accounting. Adoption of amortization accounting for these rate categories will relieve APS of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of each asset.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage parameters recommended for a) steam and other production assets; b) nuclear assets; and c) electric transmission, distribution and general plant categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of present and proposed annualized 2008 depreciation accruals based upon the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2007.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a computation of the estimated future net salvage rate for steam production facilities.
- Statement G contains the computation of terminal dismantlement costs for steam production facilities.
- Statement H provides a comparative summary of present and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Present depreciation accruals shown on Statement B are the product of the plant investment (Column B) and present depreciation rates (Column D) shown on Statement A. These are the effective rates used by the Company for the mix of investments recorded on December 31, 2007. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates (Column I) shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates

Present: BG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Net Salvage	Total	Proposed (at 12/31/2007) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION						
311.00 Structures and Improvements	3.22%	0.57%	3.79%	3.14%	0.38%	3.52%
312.00 Boiler Plant Equipment	3.39%	0.61%	4.00%	3.17%	0.41%	3.58%
314.00 Turbogenerator Units	3.03%	0.60%	3.63%	3.07%	0.39%	3.46%
315.00 Accessory Electric Equipment	2.51%	0.47%	2.98%	2.37%	0.31%	2.68%
316.00 Miscellaneous Power Plant Equipment	3.95%	0.81%	4.76%	3.90%	0.59%	4.49%
Total Steam Production Plant	3.26%	0.60%	3.86%	3.10%	0.41%	3.51%
NUCLEAR PRODUCTION						
321.00 Structures and Improvements	2.62%		2.62%	2.62%	0.01%	2.63%
322.00 Reactor Plant Equipment	2.83%	0.01%	2.84%	2.88%	0.05%	2.93%
322.10 Steam Generators	2.92%		2.92%	2.30%	0.02%	2.32%
323.00 Turbogenerator Units	2.85%	0.01%	2.86%	2.75%	0.02%	2.77%
324.00 Accessory Electric Equipment	2.69%	0.01%	2.70%	2.54%	0.01%	2.55%
325.00 Miscellaneous Power Plant Equipment	3.32%	0.03%	3.35%	2.88%	0.03%	2.91%
Total Nuclear Production Plant	2.79%	0.01%	2.80%	2.75%	0.03%	2.78%
OTHER PRODUCTION						
341.00 Structures and Improvements	2.39%	0.08%	2.47%	2.79%	0.24%	3.03%
342.00 Fuel Holders, Products and Accessories	2.51%	0.12%	2.63%	3.03%	0.15%	3.18%
343.00 Prime Movers	2.27%	0.04%	2.31%	2.60%	0.10%	2.70%
344.00 Generators and Devices	2.88%	0.06%	2.94%	3.23%	0.14%	3.37%
345.00 Accessory Electric Equipment	2.39%	0.04%	2.43%	2.80%	0.13%	2.93%
346.00 Miscellaneous Power Plant Equipment	2.59%	0.01%	2.60%	2.83%	0.15%	2.98%
Total Other Production Plant	2.54%	0.05%	2.59%	2.89%	0.13%	3.02%
TRANSMISSION PLANT						
352.02 Structures and Improvements	-0.25%	-0.01%	-0.26%	2.45%		2.45%
353.00 Station Equipment	1.35%		1.35%	2.29%		2.29%
354.00 Towers and Fixtures	1.08%	0.37%	1.45%	1.78%		1.78%
355.00 Poles and Fixtures	1.97%	0.30%	2.27%	2.03%	0.40%	2.43%
356.00 Overhead Conductors and Devices	1.54%	0.53%	2.07%	1.72%	-0.33%	1.39%
Total Transmission Plant	1.36%	0.02%	1.38%	2.26%		2.26%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	1.95%	0.20%	2.15%	1.51%	0.06%	1.57%
362.00 Station Equipment	2.12%		2.12%	2.16%	-0.21%	1.95%
364.01 Poles, Towers and Fixtures - Wood	2.37%	0.24%	2.61%	2.26%	-0.04%	2.22%
364.02 Poles, Towers and Fixtures - Steel	1.95%	0.10%	2.05%	2.75%	0.16%	2.91%
365.00 Overhead Conductors and Devices	1.80%	0.18%	1.98%	1.89%	-0.19%	1.70%
366.00 Underground Conduit	1.14%	0.06%	1.20%	1.46%	0.07%	1.53%
367.00 Underground Conductors and Devices	3.09%	0.16%	3.25%	2.76%	0.10%	2.86%
368.00 Line Transformers	2.28%	0.11%	2.39%	1.66%	0.07%	1.73%
369.00 Services	2.35%	0.23%	2.58%	2.20%		2.20%
370.01 Meters - Electronic	3.68%		3.68%	← 5 Year Amortization →		
370.02 Meters - Electromechanical	3.02%		3.02%	← 5 Year Amortization →		
370.03 Meters - AMI	3.61%		3.61%	3.82%		3.82%
371.00 Installations on Customers' Premises	1.93%	0.39%	2.32%	1.75%	0.19%	1.94%
373.00 Street Lighting and Signal Systems	2.43%	0.48%	2.91%	1.47%	0.13%	1.60%
Total Distribution Plant	2.37%	0.14%	2.51%	2.34%	0.03%	2.37%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates

Present: BG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Net Salvage	Total	Proposed (at 12/31/2007) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.56%	0.38%	2.94%	2.05%	0.11%	2.16%
391.CM Office Furn. and Equip. - Computer	12.46%		12.46%	10.19%	0.01%	10.20%
392.EL Transportation Equipment - Electric Vehic	3.67%		3.67%	5.83%	0.01%	5.84%
392.HD Transportation Equipment - Heavy Duty	2.04%		2.04%	2.41%	0.17%	2.58%
392.LD Transportation Equipment - Light Duty	10.50%		10.50%	10.14%	-1.73%	8.41%
392.MD Transportation Equipment - Medium Duty	3.25%		3.25%	3.55%		3.55%
392.TR Transportation Equipment - Trailers	1.17%		1.17%	2.54%		2.54%
396.00 Power Operated Equipment	3.32%		3.32%	3.81%	-0.11%	3.70%
397.00 Communication Equipment	5.25%		5.25%	4.72%		4.72%
Total Depreciable	5.89%	0.13%	6.02%	5.10%	-0.03%	5.07%
Amortizable						
391.FE Office Furn. and Equip. - Furniture	4.84%		4.84%	← 20 Year Amortization →		
393.00 Stores Equipment	4.83%		4.83%	← 20 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	4.99%		4.99%	← 20 Year Amortization →		
395.00 Laboratory Equipment	4.99%		4.99%	← 20 Year Amortization →		
398.00 Miscellaneous Equipment	12.94%		12.94%	← 24 Year Amortization →		
Total Amortizable	5.88%		5.88%	4.67%		4.67%
Total General Plant	5.89%	0.10%	5.99%	5.02%	-0.03%	4.99%
TOTAL UTILITY	2.77%	0.16%	2.93%	2.74%	0.10%	2.84%
STEAM PRODUCTION (by Unit)						
Cholla						
311.00 Structures and Improvements	1.93%	0.36%	2.29%	1.64%	0.18%	1.82%
312.00 Boiler Plant Equipment	2.52%	0.47%	2.99%	2.06%	0.23%	2.29%
314.00 Turbogenerator Units	2.32%	0.46%	2.78%	2.31%	0.22%	2.53%
315.00 Accessory Electric Equipment	1.99%	0.39%	2.38%	1.65%	0.18%	1.83%
316.00 Miscellaneous Power Plant Equipment	2.86%	0.54%	3.40%	2.29%	0.28%	2.57%
Total Cholla	2.37%	0.45%	2.82%	2.01%	0.22%	2.23%
Cholla Unit 1						
311.00 Structures and Improvements	2.25%	0.35%	2.60%	2.29%	0.20%	2.49%
312.00 Boiler Plant Equipment	3.67%	0.60%	4.27%	3.61%	0.37%	3.98%
314.00 Turbogenerator Units	2.97%	0.47%	3.44%	1.44%	0.13%	1.57%
315.00 Accessory Electric Equipment	2.91%	0.47%	3.38%	2.50%	0.24%	2.74%
316.00 Miscellaneous Power Plant Equipment	4.39%	0.71%	5.10%	2.15%	0.21%	2.36%
Total Cholla Unit 1	3.49%	0.57%	4.06%	3.17%	0.32%	3.49%
Cholla Unit 2						
311.00 Structures and Improvements	2.17%	0.39%	2.56%	2.02%	0.19%	2.21%
312.00 Boiler Plant Equipment	2.20%	0.42%	2.62%	1.62%	0.17%	1.79%
314.00 Turbogenerator Units	1.94%	0.35%	2.29%	2.21%	0.19%	2.40%
315.00 Accessory Electric Equipment	1.87%	0.35%	2.22%	1.50%	0.14%	1.64%
316.00 Miscellaneous Power Plant Equipment	2.54%	0.48%	3.02%	2.06%	0.21%	2.27%
Total Cholla Unit 2	2.11%	0.40%	2.51%	1.71%	0.17%	1.88%
Cholla Unit 3						
311.00 Structures and Improvements	1.87%	0.40%	2.27%	1.54%	0.19%	1.73%
312.00 Boiler Plant Equipment	2.25%	0.47%	2.72%	1.67%	0.22%	1.89%
314.00 Turbogenerator Units	2.47%	0.54%	3.01%	2.57%	0.27%	2.84%
315.00 Accessory Electric Equipment	1.93%	0.42%	2.35%	1.55%	0.20%	1.75%
316.00 Miscellaneous Power Plant Equipment	2.54%	0.53%	3.07%	2.00%	0.27%	2.27%
Total Cholla Unit 3	2.25%	0.48%	2.73%	1.88%	0.23%	2.11%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Net Salvage	Total	Proposed (at 12/31/2007) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Cholla Common						
311.00 Structures and Improvements	1.88%	0.35%	2.23%	1.55%	0.17%	1.72%
312.00 Boiler Plant Equipment	2.45%	0.48%	2.93%	2.07%	0.29%	2.36%
314.00 Turbogenerator Units	1.88%	0.36%	2.24%	2.20%	0.13%	2.33%
315.00 Accessory Electric Equipment	2.10%	0.40%	2.50%	2.22%	0.26%	2.48%
316.00 Miscellaneous Power Plant Equipment	2.81%	0.54%	3.35%	2.60%	0.33%	2.93%
Total Cholla Common	2.20%	0.42%	2.62%	1.91%	0.23%	2.14%
Four Corners						
311.00 Structures and Improvements	4.76%	0.77%	5.53%	5.18%	0.62%	5.80%
312.00 Boiler Plant Equipment	4.32%	0.72%	5.04%	4.50%	0.59%	5.09%
314.00 Turbogenerator Units	4.13%	0.67%	4.80%	4.91%	0.56%	5.47%
315.00 Accessory Electric Equipment	3.68%	0.64%	4.32%	4.07%	0.51%	4.58%
316.00 Miscellaneous Power Plant Equipment	4.66%	0.85%	5.51%	5.58%	0.74%	6.32%
Total Four Corners	4.31%	0.72%	5.03%	4.64%	0.59%	5.23%
Four Corners Units 1-3						
311.00 Structures and Improvements	5.96%	0.84%	6.80%	6.56%	0.73%	7.29%
312.00 Boiler Plant Equipment	5.18%	0.76%	5.94%	5.81%	0.71%	6.52%
314.00 Turbogenerator Units	4.77%	0.69%	5.46%	5.90%	0.64%	6.54%
315.00 Accessory Electric Equipment	4.73%	0.68%	5.41%	5.43%	0.61%	6.04%
316.00 Miscellaneous Power Plant Equipment	6.65%	0.96%	7.61%	8.65%	1.02%	9.67%
Total Four Corners Units 1-3	5.22%	0.76%	5.98%	5.96%	0.71%	6.67%
Four Corners Units 4-5						
311.00 Structures and Improvements	2.22%	0.59%	2.81%	2.12%	0.35%	2.47%
312.00 Boiler Plant Equipment	2.63%	0.63%	3.26%	1.80%	0.32%	2.12%
314.00 Turbogenerator Units	2.49%	0.65%	3.14%	2.21%	0.36%	2.57%
315.00 Accessory Electric Equipment	2.47%	0.65%	3.12%	1.96%	0.33%	2.29%
316.00 Miscellaneous Power Plant Equipment	2.95%	0.70%	3.65%	2.21%	0.38%	2.59%
Total Four Corners Units 4-5	2.58%	0.63%	3.21%	1.89%	0.33%	2.22%
Four Corners Common						
311.00 Structures and Improvements	2.42%	0.70%	3.12%	2.79%	0.46%	3.25%
312.00 Boiler Plant Equipment	2.52%	0.63%	3.15%	2.71%	0.48%	3.19%
314.00 Turbogenerator Units	1.65%	0.44%	2.09%	2.20%	0.32%	2.52%
315.00 Accessory Electric Equipment	1.80%	0.45%	2.25%	2.95%	0.49%	3.44%
316.00 Miscellaneous Power Plant Equipment	2.91%	0.76%	3.67%	3.09%	0.54%	3.63%
Total Four Corners Common	2.48%	0.64%	3.12%	2.82%	0.49%	3.31%
Navajo Units 1-3						
311.00 Structures and Improvements	2.95%	0.43%	3.38%	2.63%	0.27%	2.90%
312.00 Boiler Plant Equipment	3.15%	0.50%	3.65%	2.80%	0.32%	3.12%
314.00 Turbogenerator Units	2.49%	0.37%	2.86%	2.06%	0.22%	2.28%
315.00 Accessory Electric Equipment	2.55%	0.38%	2.93%	2.19%	0.24%	2.43%
316.00 Miscellaneous Power Plant Equipment	3.49%	0.55%	4.04%	3.22%	0.36%	3.58%
Total Navajo Units 1-3	3.04%	0.47%	3.51%	2.69%	0.30%	2.99%
Ocotillo Units 1-2						
311.00 Structures and Improvements	3.70%	1.41%	5.11%	3.59%	1.02%	4.61%
312.00 Boiler Plant Equipment	3.23%	1.06%	4.29%	2.83%	0.85%	3.68%
314.00 Turbogenerator Units	2.94%	1.07%	4.01%	2.64%	0.79%	3.43%
315.00 Accessory Electric Equipment	3.09%	1.08%	4.17%	3.12%	0.91%	4.03%
316.00 Miscellaneous Power Plant Equipment	5.35%	1.97%	7.32%	5.26%	1.52%	6.78%
Total Ocotillo Units 1-2	3.40%	1.19%	4.59%	3.10%	0.92%	4.02%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Net Salvage	Total	Proposed (at 12/31/2007) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro Units 1-2						
311.00 Structures and Improvements	4.68%	1.36%	6.04%	2.81%	0.80%	3.61%
312.00 Boiler Plant Equipment	4.39%	1.22%	5.61%	2.47%	0.71%	3.18%
314.00 Turbogenerator Units	3.66%	1.06%	4.72%	2.04%	0.59%	2.63%
315.00 Accessory Electric Equipment	3.40%	0.97%	4.37%	4.27%	1.23%	5.50%
316.00 Miscellaneous Power Plant Equipment	6.37%	1.81%	8.18%	3.95%	1.16%	5.11%
Total Saguaro Units 1-2	4.20%	1.19%	5.39%	2.62%	0.76%	3.38%
NUCLEAR PRODUCTION (by Unit)						
Palo Verde						
321.00 Structures and Improvements	2.62%		2.62%	2.62%	0.01%	2.63%
322.00 Reactor Plant Equipment	2.83%	0.01%	2.84%	2.88%	0.05%	2.93%
322.10 Steam Generators	2.92%		2.92%	2.30%	0.02%	2.32%
323.00 Turbogenerator Units	2.85%	0.01%	2.86%	2.75%	0.02%	2.77%
324.00 Accessory Electric Equipment	2.69%	0.01%	2.70%	2.54%	0.01%	2.55%
325.00 Miscellaneous Power Plant Equipment	3.32%	0.03%	3.35%	2.88%	0.03%	2.91%
Total Palo Verde	2.79%	0.01%	2.80%	2.75%	0.03%	2.78%
Palo Verde Unit 1						
321.00 Structures and Improvements	2.63%		2.63%	2.66%	0.01%	2.67%
322.00 Reactor Plant Equipment	2.76%		2.76%	3.16%	0.04%	3.20%
322.10 Steam Generators	1.47%		1.47%			
323.00 Turbogenerator Units	2.83%	0.01%	2.84%	3.01%	0.01%	3.02%
324.00 Accessory Electric Equipment	2.69%	0.01%	2.70%	2.64%	0.01%	2.65%
325.00 Miscellaneous Power Plant Equipment	3.25%	0.03%	3.28%	2.86%	0.03%	2.89%
Total Palo Verde Unit 1	2.75%		2.75%	2.97%	0.02%	2.99%
Palo Verde Unit 2						
321.00 Structures and Improvements	2.73%		2.73%	2.66%	0.01%	2.67%
322.00 Reactor Plant Equipment	3.21%	0.01%	3.22%	3.09%	0.08%	3.17%
322.10 Steam Generators						
323.00 Turbogenerator Units	3.12%	0.01%	3.13%	2.93%	0.02%	2.95%
324.00 Accessory Electric Equipment	2.85%	0.01%	2.86%	2.69%	0.01%	2.70%
325.00 Miscellaneous Power Plant Equipment	3.61%	0.02%	3.63%	3.05%	0.02%	3.07%
Total Palo Verde Unit 2	3.09%	0.01%	3.10%	2.94%	0.04%	2.98%
Palo Verde Unit 3						
321.00 Structures and Improvements	2.52%		2.52%	2.34%		2.34%
322.00 Reactor Plant Equipment	2.66%	0.01%	2.67%	2.38%	0.05%	2.43%
322.10 Steam Generators	2.92%		2.92%	2.30%	0.02%	2.32%
323.00 Turbogenerator Units	2.72%	0.01%	2.73%	2.42%	0.01%	2.43%
324.00 Accessory Electric Equipment	2.61%	0.01%	2.62%	2.34%	0.01%	2.35%
325.00 Miscellaneous Power Plant Equipment	3.17%	0.03%	3.20%	2.51%	0.02%	2.53%
Total Palo Verde Unit 3	2.66%	0.01%	2.67%	2.38%	0.02%	2.40%
Palo Verde Water Reclamation						
321.00 Structures and Improvements	2.66%		2.66%	2.84%	0.02%	2.86%
322.00 Reactor Plant Equipment	4.06%	0.01%	4.07%	3.93%	0.03%	3.96%
322.10 Steam Generators						
323.00 Turbogenerator Units	3.06%	0.01%	3.07%	2.85%	0.02%	2.87%
324.00 Accessory Electric Equipment						
325.00 Miscellaneous Power Plant Equipment	3.42%	0.03%	3.45%	2.83%	0.05%	2.88%
Total Palo Verde Water Reclamation	2.66%		2.66%	2.84%	0.02%	2.86%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Net Salvage	Total	Proposed (at 12/31/2007) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Palo Verde Common						
321.00 Structures and Improvements	2.61%		2.61%	2.64%	0.02%	2.66%
322.00 Reactor Plant Equipment	2.73%	0.01%	2.74%	2.48%	0.08%	2.56%
322.10 Steam Generators						
323.00 Turbogenerator Units	3.12%	0.01%	3.13%	4.38%	0.06%	4.44%
324.00 Accessory Electric Equipment	2.67%	0.01%	2.68%	2.51%	0.01%	2.52%
325.00 Miscellaneous Power Plant Equipment	3.29%	0.03%	3.32%	2.99%	0.06%	3.05%
Total Palo Verde Common	2.81%	0.01%	2.82%	2.71%	0.04%	2.75%
OTHER PRODUCTION (by Unit)						
Douglas CT						
341.00 Structures and Improvements	0.71%	0.03%	0.74%	5.94%	0.29%	6.23%
342.00 Fuel Holders, Products and Accessories	1.92%	0.09%	2.01%	1.82%	0.06%	1.88%
343.00 Prime Movers	0.71%		0.71%	0.73%	0.04%	0.77%
344.00 Generators and Devices	0.12%		0.12%	0.70%	0.03%	0.73%
345.00 Accessory Electric Equipment	0.89%		0.89%	0.98%	0.07%	1.05%
346.00 Miscellaneous Power Plant Equipment	1.85%		1.85%	1.65%	0.08%	1.73%
Total Douglas CT	0.69%	0.01%	0.70%	0.96%	0.05%	1.01%
Ocotillo CT Units 1-2						
341.00 Structures and Improvements	2.34%	0.12%	2.46%	2.02%	0.10%	2.12%
342.00 Fuel Holders, Products and Accessories	2.16%	0.11%	2.27%	1.93%	0.09%	2.02%
343.00 Prime Movers	1.38%		1.38%	1.26%	0.06%	1.32%
344.00 Generators and Devices	3.34%		3.34%	3.26%	0.13%	3.39%
345.00 Accessory Electric Equipment	1.69%		1.69%	1.68%	0.10%	1.78%
346.00 Miscellaneous Power Plant Equipment	1.97%		1.97%	1.77%	0.08%	1.85%
Total Octillo CT Units 1-2	2.29%	0.01%	2.30%	2.18%	0.10%	2.28%
Redhawk CC Units 1-2						
341.00 Structures and Improvements	2.67%	0.08%	2.75%	3.01%	0.42%	3.43%
342.00 Fuel Holders, Products and Accessories	2.67%	0.08%	2.75%	3.46%	0.17%	3.63%
343.00 Prime Movers	2.67%	0.08%	2.75%	2.98%	0.07%	3.05%
344.00 Generators and Devices	2.67%	0.08%	2.75%	3.02%	0.12%	3.14%
345.00 Accessory Electric Equipment	2.67%	0.08%	2.75%	2.99%	0.12%	3.11%
346.00 Miscellaneous Power Plant Equipment	2.67%	0.08%	2.75%	3.27%	0.17%	3.44%
Total Redhawk CC Units 1-2	2.67%	0.08%	2.75%	3.00%	0.12%	3.12%
Saguaro						
341.00 Structures and Improvements	4.65%	0.23%	4.88%	3.82%	0.19%	4.01%
342.00 Fuel Holders, Products and Accessories	1.74%	0.09%	1.83%	1.62%	0.07%	1.69%
343.00 Prime Movers	1.54%		1.54%	1.38%	0.06%	1.44%
344.00 Generators and Devices	2.85%		2.85%	3.10%	0.15%	3.25%
345.00 Accessory Electric Equipment	1.44%		1.44%	1.35%	0.08%	1.43%
346.00 Miscellaneous Power Plant Equipment	3.42%		3.42%	3.20%	0.16%	3.36%
Total Saguaro	2.59%	0.01%	2.60%	2.70%	0.13%	2.83%
Saguaro CT Units 1-2						
341.00 Structures and Improvements	4.65%	0.23%	4.88%	3.82%	0.19%	4.01%
342.00 Fuel Holders, Products and Accessories	1.74%	0.09%	1.83%	1.62%	0.07%	1.69%
343.00 Prime Movers	1.44%		1.44%	1.25%	0.06%	1.31%
344.00 Generators and Devices	3.67%		3.67%	4.08%	0.18%	4.26%
345.00 Accessory Electric Equipment	1.34%		1.34%	1.23%	0.07%	1.30%
346.00 Miscellaneous Power Plant Equipment	3.42%		3.42%	3.20%	0.16%	3.36%
Total Saguaro CT Units 1-2	2.37%	0.03%	2.40%	2.30%	0.10%	2.40%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates

Present: BG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Net Salvage	Total	Proposed (at 12/31/2007) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro CT Unit 3						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.72%		2.72%	2.94%	0.15%	3.09%
344.00 Generators and Devices	2.72%		2.72%	2.94%	0.15%	3.09%
345.00 Accessory Electric Equipment	2.72%		2.72%	2.94%	0.15%	3.09%
346.00 Miscellaneous Power Plant Equipment						
Total Saguaro CT Unit 3	2.72%		2.72%	2.94%	0.15%	3.09%
Solar Units						
341.00 Structures and Improvements	-10.58%	-0.01%	-10.59%	0.52%	0.02%	0.54%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	6.04%		6.04%	5.59%	0.31%	5.90%
345.00 Accessory Electric Equipment	6.30%		6.30%	5.36%	0.27%	5.63%
346.00 Miscellaneous Power Plant Equipment						
Total Solar Units	5.61%		5.61%	5.45%	0.31%	5.76%
Sundance						
341.00 Structures and Improvements	1.94%		1.94%	2.21%	0.11%	2.32%
342.00 Fuel Holders, Products and Accessories	1.93%		1.93%	2.19%	0.11%	2.30%
343.00 Prime Movers	1.94%		1.94%	2.20%	0.11%	2.31%
344.00 Generators and Devices	2.14%		2.14%	3.02%	0.15%	3.17%
345.00 Accessory Electric Equipment	1.92%		1.92%	2.19%	0.11%	2.30%
346.00 Miscellaneous Power Plant Equipment	1.92%		1.92%	2.19%	0.11%	2.30%
Total Sun Dance	1.94%		1.94%	2.20%	0.11%	2.31%
West Phoenix						
341.00 Structures and Improvements	2.45%	0.12%	2.57%	2.86%	0.16%	3.02%
342.00 Fuel Holders, Products and Accessories	2.83%	0.15%	2.98%	3.51%	0.18%	3.69%
343.00 Prime Movers	2.46%	0.05%	2.51%	2.97%	0.12%	3.09%
344.00 Generators and Devices	2.92%	0.06%	2.98%	3.33%	0.16%	3.49%
345.00 Accessory Electric Equipment	2.78%	0.05%	2.83%	3.37%	0.16%	3.53%
346.00 Miscellaneous Power Plant Equipment	2.81%		2.81%	3.11%	0.17%	3.28%
Total West Phoenix	2.72%	0.06%	2.78%	3.20%	0.14%	3.34%
West Phoenix CC Units 1-3						
341.00 Structures and Improvements	2.45%	0.12%	2.57%	4.01%	0.19%	4.20%
342.00 Fuel Holders, Products and Accessories	3.08%	0.16%	3.24%	3.75%	0.19%	3.94%
343.00 Prime Movers						
344.00 Generators and Devices	3.23%	0.07%	3.30%	3.83%	0.16%	3.99%
345.00 Accessory Electric Equipment	2.94%		2.94%	3.77%	0.18%	3.95%
346.00 Miscellaneous Power Plant Equipment	2.56%		2.56%	2.98%	0.16%	3.14%
Total West Phoenix CC Units 1-3	3.14%	0.08%	3.22%	3.80%	0.17%	3.97%
West Phoenix CC Unit 4						
341.00 Structures and Improvements	1.85%	0.09%	1.94%	3.04%	0.15%	3.19%
342.00 Fuel Holders, Products and Accessories	1.90%	0.09%	1.99%	2.98%	0.15%	3.13%
343.00 Prime Movers	1.95%	0.04%	1.99%	2.98%	0.15%	3.13%
344.00 Generators and Devices	2.51%	0.05%	2.56%	3.02%	0.16%	3.18%
345.00 Accessory Electric Equipment	2.08%	0.10%	2.18%	3.25%	0.16%	3.41%
346.00 Miscellaneous Power Plant Equipment	1.96%	0.09%	2.05%	3.19%	0.16%	3.35%
Total West Phoenix CC Unit 4	2.05%	0.05%	2.10%	2.99%	0.15%	3.14%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Net Salvage	Total	Proposed (at 12/31/2007) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
West Phoenix CC Unit 5						
341.00 Structures and Improvements	2.74%	0.14%	2.88%	3.02%	0.16%	3.18%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.74%	0.06%	2.80%	3.06%	0.10%	3.16%
344.00 Generators and Devices	2.74%	0.06%	2.80%	3.03%	0.15%	3.18%
345.00 Accessory Electric Equipment	2.74%	0.14%	2.88%	3.02%	0.15%	3.17%
346.00 Miscellaneous Power Plant Equipment	2.74%	0.14%	2.88%	3.18%	0.16%	3.34%
Total West Phoenix CC Unit 5	2.74%	0.07%	2.81%	3.04%	0.13%	3.17%
West Phoenix CT Units 1-2						
341.00 Structures and Improvements	1.55%	0.08%	1.63%	1.36%	0.07%	1.43%
342.00 Fuel Holders, Products and Accessories	1.81%	0.10%	1.91%	1.57%	0.08%	1.65%
343.00 Prime Movers	2.33%		2.33%	1.95%	0.08%	2.03%
344.00 Generators and Devices	2.91%		2.91%	2.48%	0.13%	2.61%
345.00 Accessory Electric Equipment	1.47%	-0.01%	1.46%	1.83%	0.10%	1.93%
346.00 Miscellaneous Power Plant Equipment	3.50%		3.50%	3.46%	0.17%	3.63%
Total West Phoenix CT Units 1-2	2.41%	0.01%	2.42%	2.12%	0.10%	2.22%
West Phoenix Common						
341.00 Structures and Improvements	2.45%	0.12%	2.57%	1.59%	0.13%	1.72%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total West Phoenix Common	2.45%	0.12%	2.57%	1.59%	0.13%	1.72%
Yucca CT Units 1-4						
341.00 Structures and Improvements	3.68%	0.19%	3.87%	3.58%	0.17%	3.75%
342.00 Fuel Holders, Products and Accessories	0.91%	0.04%	0.95%	0.81%	0.04%	0.85%
343.00 Prime Movers	0.62%		0.62%	0.58%	0.03%	0.61%
344.00 Generators and Devices	1.39%		1.39%	2.61%	0.12%	2.73%
345.00 Accessory Electric Equipment	1.25%	-0.01%	1.24%	2.36%	0.13%	2.49%
346.00 Miscellaneous Power Plant Equipment	1.81%		1.81%	2.37%	0.11%	2.48%
Total Yucca CT Units 1-4	1.08%	0.01%	1.09%	1.58%	0.07%	1.65%

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION								
311.00 Structures and Improvements	$139,734,640	$4,496,087	$791,691	$5,287,778	$4,383,445	$536,541	$4,919,986	($367,792)
312.00 Boiler Plant Equipment	912,545,152	30,975,416	5,540,871	36,516,287	28,898,695	3,775,329	32,674,024	(3,842,263)
314.00 Turbogenerator Units	226,414,540	6,850,237	1,357,472	8,207,709	6,946,269	884,936	7,831,205	(376,504)
315.00 Accessory Electric Equipment	151,610,085	3,802,343	719,519	4,521,862	3,595,227	466,001	4,061,228	(460,634)
316.00 Miscellaneous Power Plant Equipment	72,551,134	2,869,349	588,657	3,458,006	2,831,526	425,100	3,256,626	(201,380)
Total Steam Production Plant	$1,502,855,551	$48,993,432	$8,998,210	$57,991,642	$46,655,162	$6,087,907	$52,743,069	($5,248,573)
NUCLEAR PRODUCTION								
321.00 Structures and Improvements	$657,537,995	$17,227,283		$17,227,283	$17,207,620	$74,875	$17,282,495	$55,212
322.00 Reactor Plant Equipment	1,014,755,344	28,696,901	57,789	28,754,690	29,197,172	539,604	29,736,776	982,086
322.10 Steam Generators	25,412,774	742,053		742,053	584,494	5,083	589,577	(152,476)
323.00 Turbogenerator Units	346,650,191	9,882,794	34,665	9,917,459	9,546,216	43,537	9,589,753	(327,706)
324.00 Accessory Electric Equipment	272,678,334	7,339,797	27,268	7,367,065	6,931,265	27,268	6,958,533	(408,532)
325.00 Miscellaneous Power Plant Equipment	137,397,362	4,561,053	38,538	4,599,591	3,952,228	51,603	4,003,831	(595,760)
Total Nuclear Production Plant	$2,454,432,000	$68,449,881	$158,260	$68,608,141	$67,418,995	$741,970	$68,160,965	($447,176)
OTHER PRODUCTION								
341.00 Structures and Improvements	$60,205,926	$1,439,862	$50,665	$1,490,527	$1,678,810	$144,111	$1,822,921	$332,394
342.00 Fuel Holders, Products and Accessories	37,976,537	951,378	43,725	995,103	1,151,231	57,882	1,209,113	214,010
343.00 Prime Movers	594,075,488	13,465,190	222,972	13,688,162	15,435,892	578,312	16,014,204	2,326,042
344.00 Generators and Devices	537,620,446	15,461,717	338,890	15,800,607	17,361,489	764,870	18,126,359	2,325,752
345.00 Accessory Electric Equipment	84,524,062	2,019,337	33,694	2,053,031	2,364,080	111,225	2,475,305	422,274
346.00 Miscellaneous Power Plant Equipment	7,792,828	201,772	613	202,385	220,919	11,273	232,192	29,807
Total Other Production Plant	$1,322,195,287	$33,539,256	$690,559	$34,229,815	$38,212,421	$1,667,673	$39,880,094	$5,650,279
TRANSMISSION PLANT								
352.02 Structures and Improvements	$95,935	($240)	($10)	($250)	$2,350		$2,350	$2,600
353.00 Station Equipment	77,712,529	1,049,119		1,049,119	1,779,617		1,779,617	730,498
354.00 Towers and Fixtures	1,329,316	14,357	4,918	19,275	23,662		23,662	4,387
355.00 Poles and Fixtures	1,366,890	26,928	4,101	31,029	27,748	5,468	33,216	2,187
356.00 Overhead Conductors and Devices	1,947,677	29,994	10,323	40,317	33,500	(6,427)	27,073	(13,244)
Total Transmission Plant	$82,452,347	$1,120,158	$19,332	$1,139,490	$1,866,877	($959)	$1,865,918	$726,428
DISTRIBUTION PLANT								
361.00 Structures and Improvements	$38,286,283	$746,583	$76,573	$823,156	$578,123	$22,972	$601,095	($222,061)
362.00 Station Equipment	324,622,763	6,882,003		6,882,003	7,011,852	(681,708)	6,330,144	(551,859)
364.01 Poles, Towers and Fixtures - Wood	306,109,637	7,254,798	734,663	7,989,461	6,918,078	(122,444)	6,795,634	(1,193,827)
364.02 Poles, Towers and Fixtures - Steel	130,459,890	2,543,968	130,460	2,674,428	3,587,647	208,736	3,796,383	1,121,955
365.00 Overhead Conductors and Devices	272,581,755	4,906,472	490,647	5,397,119	5,151,795	(517,905)	4,633,890	(763,229)
366.00 Underground Conduit	577,756,928	6,586,429	346,654	6,933,083	8,435,251	404,430	8,839,681	1,906,598

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
367.00 Underground Conductors and Devices	1,234,823,572	38,156,048	1,975,718	40,131,766	34,081,131	1,234,824	35,315,955	(4,815,811)
368.00 Line Transformers	653,512,139	14,900,077	718,863	15,618,940	10,848,302	457,458	11,305,760	(4,313,180)
369.00 Services	309,417,647	7,271,315	711,661	7,982,976	6,807,188		6,807,188	(1,175,788)
370.01 Meters - Electronic	93,968,807	3,458,052		3,458,052	11,022,541		11,022,541	7,564,489
370.02 Meters - Electromechanical	72,160,378	2,179,243		2,179,243	101,025		101,025	(2,078,218)
370.03 Meters - AMI	14,033,538	506,611		506,611	536,081		536,081	29,470
371.00 Installations on Customers' Premises	39,046,677	753,601	152,282	905,883	683,317	74,189	757,506	(148,377)
373.00 Street Lighting and Signal Systems	70,437,334	1,711,627	338,099	2,049,726	1,035,429	91,569	1,126,998	(922,728)
Total Distribution Plant	$4,137,217,348	$97,856,827	$5,675,620	$103,532,447	$96,797,760	$1,172,121	$97,969,881	($5,562,566)
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$111,657,425	$2,858,430	$424,298	$3,282,728	$2,288,977	$122,823	$2,411,800	($870,928)
391.CM Office Furn. and Equip. - Computer	69,159,918	8,617,326		8,617,326	7,047,396	6,916	7,054,312	(1,563,014)
392.EL Transportation Equipment - Electric Vehi	1,698,104	62,320		62,320	98,999	170	99,169	36,849
392.HD Transportation Equipment - Heavy Duty	3,626,209	73,975		73,975	87,392	6,165	93,557	19,582
392.LD Transportation Equipment - Light Duty	14,285,978	1,500,028		1,500,028	1,448,598	(247,147)	1,201,451	(298,577)
392.MD Transportation Equipment - Medium Duty	1,392,936	45,270		45,270	49,449		49,449	4,179
392.TR Transportation Equipment - Trailers	4,428,889	51,818		51,818	112,494		112,494	60,676
396.00 Power Operated Equipment	10,707,227	355,480		355,480	407,945	(11,778)	396,167	40,687
397.00 Communication Equipment	120,998,470	6,352,420		6,352,420	5,711,128		5,711,128	(641,292)
Total Depreciable	$337,955,156	$19,917,067	$424,298	$20,341,365	$17,252,378	($122,851)	$17,129,527	($3,211,838)
Amortizable								
391.FE Office Furn. and Equip. - Furniture	$51,190,495	$2,477,620		$2,477,620	$2,452,025		$2,452,025	($25,595)
393.00 Stores Equipment	1,237,565	59,774		59,774	4,455		4,455	(55,319)
394.00 Tools, Shop and Garage Equipment	20,539,378	1,024,915		1,024,915	1,008,483		1,008,483	(16,432)
395.00 Laboratory Equipment	1,894,538	94,537		94,537	83,549		83,549	(10,988)
398.00 Miscellaneous Equipment	10,510,399	1,360,046		1,360,046	436,182		436,182	(923,864)
Total Amortizable	$85,372,375	$5,016,892		$5,016,892	$3,984,694		$3,984,694	($1,032,198)
Total General Plant	$423,327,531	$24,933,959	$424,298	$25,358,257	$21,237,072	($122,851)	$21,114,221	($4,244,036)
TOTAL UTILITY	$9,922,480,064	$274,893,513	$15,966,279	$290,859,792	$272,188,287	$9,545,861	$281,734,148	($9,125,644)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION (by Unit)								
Cholla								
311.00 Structures and Improvements	$57,025,813	$1,100,416	$206,681	$1,307,097	$935,547	$101,093	$1,036,640	($270,457)
312.00 Boiler Plant Equipment	350,284,053	8,829,096	1,663,274	10,492,370	7,205,812	817,329	8,023,141	(2,469,229)
314.00 Turbogenerator Units	101,616,123	2,359,470	467,386	2,826,856	2,346,332	227,249	2,573,581	(253,275)
315.00 Accessory Electric Equipment	89,687,352	1,788,718	347,716	2,136,434	1,482,779	159,363	1,642,142	(494,292)
316.00 Miscellaneous Power Plant Equipment	22,758,920	649,861	123,086	772,947	521,842	62,456	584,298	(188,649)
Total Cholla	$621,372,261	$14,727,561	$2,808,143	$17,535,704	$12,492,312	$1,367,490	$13,859,802	($3,675,902)
Cholla Unit 1								
311.00 Structures and Improvements	$3,648,903	$82,100	$12,771	$94,871	$83,560	$7,298	$90,858	($4,013)
312.00 Boiler Plant Equipment	68,193,466	2,502,700	409,161	2,911,861	2,461,784	252,316	2,714,100	(197,761)
314.00 Turbogenerator Units	11,111,084	329,999	52,222	382,221	160,000	14,444	174,444	(207,777)
315.00 Accessory Electric Equipment	7,508,911	218,509	35,292	253,801	187,723	18,021	205,744	(48,057)
316.00 Miscellaneous Power Plant Equipment	2,432,224	106,775	17,269	124,044	52,293	5,108	57,401	(66,643)
Total Cholla Unit 1	$92,894,588	$3,240,083	$526,715	$3,766,798	$2,945,360	$297,187	$3,242,547	($524,251)
Cholla Unit 2								
311.00 Structures and Improvements	$5,452,541	$118,320	$21,265	$139,585	$110,141	$10,360	$120,501	($19,084)
312.00 Boiler Plant Equipment	148,802,569	3,273,657	624,971	3,898,628	2,410,602	252,964	2,663,566	(1,235,062)
314.00 Turbogenerator Units	37,854,762	734,382	132,492	866,874	836,590	71,924	908,514	41,640
315.00 Accessory Electric Equipment	44,885,780	839,364	157,100	996,464	673,287	62,840	736,127	(260,337)
316.00 Miscellaneous Power Plant Equipment	5,812,164	147,629	27,898	175,527	119,731	12,206	131,937	(43,590)
Total Cholla Unit 2	$242,807,816	$5,113,352	$963,726	$6,077,078	$4,150,351	$410,294	$4,560,645	($1,516,433)
Cholla Unit 3								
311.00 Structures and Improvements	$9,819,620	$183,627	$39,278	$222,905	$151,222	$18,657	$169,879	($53,026)
312.00 Boiler Plant Equipment	106,408,931	2,394,201	500,122	2,894,323	1,777,029	234,100	2,011,129	(883,194)
314.00 Turbogenerator Units	51,739,505	1,277,966	279,393	1,557,359	1,329,705	139,697	1,469,402	(87,957)
315.00 Accessory Electric Equipment	30,765,519	593,775	129,215	722,990	476,866	61,531	538,397	(184,593)
316.00 Miscellaneous Power Plant Equipment	4,593,291	116,670	24,344	141,014	91,866	12,402	104,268	(36,746)
Total Cholla Unit 3	$203,326,866	$4,566,239	$972,352	$5,538,591	$3,826,688	$466,387	$4,293,075	($1,245,516)
Cholla Common								
311.00 Structures and Improvements	$38,104,749	$716,369	$133,367	$849,736	$590,624	$64,778	$655,402	($194,334)
312.00 Boiler Plant Equipment	26,879,087	658,538	129,020	787,558	556,397	77,949	634,346	(153,212)
314.00 Turbogenerator Units	910,772	17,123	3,279	20,402	20,037	1,184	21,221	819
315.00 Accessory Electric Equipment	6,527,142	137,070	26,109	163,179	144,903	16,971	161,874	(1,305)
316.00 Miscellaneous Power Plant Equipment	9,921,241	278,787	53,575	332,362	257,952	32,740	290,692	(41,670)
Total Cholla Common	$82,342,991	$1,807,887	$345,350	$2,153,237	$1,569,913	$193,622	$1,763,535	($389,702)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Four Corners								
311.00 Structures and Improvements	$48,283,791	$2,298,922	$371,428	$2,670,350	$2,500,588	$297,871	$2,798,459	$128,109
312.00 Boiler Plant Equipment	353,157,905	15,256,020	2,529,996	17,786,016	15,906,209	2,069,703	17,975,912	189,896
314.00 Turbogenerator Units	68,213,063	2,819,407	459,169	3,278,576	3,348,420	384,476	3,732,896	454,320
315.00 Accessory Electric Equipment	33,335,936	1,227,383	214,117	1,441,500	1,357,424	170,143	1,527,567	86,067
316.00 Miscellaneous Power Plant Equipment	24,153,428	1,126,607	204,284	1,330,891	1,346,945	179,654	1,526,599	195,708
Total Four Corners	$527,144,123	$22,728,339	$3,778,994	$26,507,333	$24,459,586	$3,101,847	$27,561,433	$1,054,100
Four Corners Units 1-3								
311.00 Structures and Improvements	$32,557,195	$1,940,409	$273,480	$2,213,889	$2,135,752	$237,668	$2,373,420	$159,531
312.00 Boiler Plant Equipment	234,692,935	12,157,094	1,783,666	13,940,760	13,635,660	1,666,320	15,301,980	1,361,220
314.00 Turbogenerator Units	49,894,597	2,379,972	344,273	2,724,245	2,943,781	319,325	3,263,106	538,861
315.00 Accessory Electric Equipment	19,105,566	903,693	129,918	1,033,611	1,037,432	116,544	1,153,976	120,365
316.00 Miscellaneous Power Plant Equipment	11,296,591	751,223	108,447	859,670	977,155	115,225	1,092,380	232,710
Total Four Corners Units 1-3	$347,546,884	$18,132,391	$2,639,784	$20,772,175	$20,729,780	$2,455,082	$23,184,862	$2,412,687
Four Corners Units 4-5								
311.00 Structures and Improvements	$11,035,183	$244,981	$65,108	$310,089	$233,946	$38,623	$272,569	($37,520)
312.00 Boiler Plant Equipment	103,280,404	2,716,275	650,667	3,366,942	1,859,047	330,497	2,189,544	(1,177,398)
314.00 Turbogenerator Units	16,330,966	406,641	106,151	512,792	360,914	58,791	419,705	(93,087)
315.00 Accessory Electric Equipment	10,081,177	249,005	65,528	314,533	197,591	33,268	230,859	(83,674)
316.00 Miscellaneous Power Plant Equipment	3,123,482	92,143	21,864	114,007	69,029	11,869	80,898	(33,109)
Total Four Corners Units 4-5	$143,851,212	$3,709,045	$909,318	$4,618,363	$2,720,527	$473,048	$3,193,575	($1,424,788)
Four Corners Common								
311.00 Structures and Improvements	$4,691,413	$113,532	$32,840	$146,372	$130,890	$21,580	$152,470	$6,098
312.00 Boiler Plant Equipment	15,184,566	382,651	95,663	478,314	411,502	72,886	484,388	6,074
314.00 Turbogenerator Units	1,987,500	32,794	8,745	41,539	43,725	6,360	50,085	8,546
315.00 Accessory Electric Equipment	4,149,193	74,685	18,671	93,356	122,401	20,331	142,732	49,376
316.00 Miscellaneous Power Plant Equipment	9,733,355	283,241	73,973	357,214	300,761	52,560	353,321	(3,893)
Total Four Corners Common	$35,746,027	$886,903	$229,892	$1,116,795	$1,009,279	$173,717	$1,182,996	$66,201
Navajo Units 1-3								
311.00 Structures and Improvements	$27,580,268	$813,618	$118,595	$932,213	$725,361	$74,467	$799,828	($132,385)
312.00 Boiler Plant Equipment	161,702,139	5,093,617	808,511	5,902,128	4,527,660	517,447	5,045,107	(857,021)
314.00 Turbogenerator Units	24,699,305	615,013	91,387	706,400	508,806	54,338	563,144	(143,256)
315.00 Accessory Electric Equipment	20,805,398	530,538	79,061	609,599	455,638	49,933	505,571	(104,028)
316.00 Miscellaneous Power Plant Equipment	16,797,235	586,224	92,385	678,609	540,871	60,470	601,341	(77,268)
Total Navajo Units 1-3	$251,584,345	$7,639,010	$1,189,939	$8,828,949	$6,758,336	$756,655	$7,514,991	($1,313,958)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Ocotillo Units 1-2								
311.00 Structures and Improvements	$3,796,298	$140,463	$53,528	$193,991	$136,287	$38,722	$175,009	($18,982)
312.00 Boiler Plant Equipment	24,502,039	791,416	259,722	1,051,138	693,408	208,267	901,675	(149,463)
314.00 Turbogenerator Units	15,372,486	451,951	164,486	616,437	405,834	121,443	527,277	(89,160)
315.00 Accessory Electric Equipment	2,859,128	88,347	30,879	119,226	89,205	26,018	115,223	(4,003)
316.00 Miscellaneous Power Plant Equipment	5,544,025	296,605	109,217	405,822	291,616	84,269	375,885	(29,937)
Total Ocotillo Units 1-2	$52,073,976	$1,768,782	$617,832	$2,386,614	$1,616,350	$478,719	$2,095,069	($291,545)
Saguaro Units 1-2								
311.00 Structures and Improvements	$3,048,470	$142,668	$41,459	$184,127	$85,662	$24,388	$110,050	($74,077)
312.00 Boiler Plant Equipment	22,899,016	1,005,267	279,368	1,284,635	565,606	162,583	728,189	(556,446)
314.00 Turbogenerator Units	16,513,563	604,396	175,044	779,440	336,877	97,430	434,307	(345,133)
315.00 Accessory Electric Equipment	4,922,271	167,357	47,746	215,103	210,181	60,544	270,725	55,622
316.00 Miscellaneous Power Plant Equipment	3,297,526	210,052	59,685	269,737	130,252	38,251	168,503	(101,234)
Total Saguaro Units 1-2	$50,680,846	$2,129,740	$603,302	$2,733,042	$1,328,578	$383,196	$1,711,774	($1,021,268)
NUCLEAR PRODUCTION (by Unit)								
Palo Verde								
321.00 Structures and Improvements	$657,537,995	$17,227,283		$17,227,283	$17,207,620	$74,875	$17,282,495	$55,212
322.00 Reactor Plant Equipment	1,014,755,344	28,696,901	57,789	28,754,690	29,197,172	539,604	29,736,776	982,086
322.10 Steam Generators	25,412,774	742,053		742,053	584,494	5,083	589,577	(152,476)
323.00 Turbogenerator Units	346,650,191	9,882,794	34,665	9,917,459	9,546,216	43,537	9,589,753	(327,706)
324.00 Accessory Electric Equipment	272,678,334	7,339,797	27,268	7,367,065	6,931,265	27,268	6,958,533	(408,532)
325.00 Miscellaneous Power Plant Equipment	137,397,362	4,561,053	38,538	4,599,591	3,952,228	51,603	4,003,831	(595,760)
Total Palo Verde	$2,454,432,000	$68,449,881	$158,260	$68,608,141	$67,418,995	$741,970	$68,160,965	($447,176)
Palo Verde Unit 1								
321.00 Structures and Improvements	$155,161,288	$4,080,742		$4,080,742	$4,127,290	$15,516	$4,142,806	$62,064
322.00 Reactor Plant Equipment	436,859,649	12,057,326		12,057,326	13,804,765	174,744	13,979,509	1,922,183
322.10 Steam Generators								
323.00 Turbogenerator Units	121,659,550	3,442,965	12,166	3,455,131	3,661,952	12,166	3,674,118	218,987
324.00 Accessory Electric Equipment	114,704,738	3,085,557	11,470	3,097,027	3,028,205	11,470	3,039,675	(57,352)
325.00 Miscellaneous Power Plant Equipment	30,135,442	979,402	9,041	988,443	861,874	9,041	870,915	(117,528)
Total Palo Verde Unit 1	$858,520,667	$23,645,992	$32,677	$23,678,669	$25,484,086	$222,937	$25,707,023	$2,028,354

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Palo Verde Unit 2								
321.00 Structures and Improvements	$90,571,765	$2,472,609		$2,472,609	$2,409,209	$9,057	$2,418,266	($54,343)
322.00 Reactor Plant Equipment	226,769,607	7,279,304	22,677	7,301,981	7,007,181	181,416	7,188,597	(113,384)
322.10 Steam Generators								
323.00 Turbogenerator Units	77,670,724	2,423,327	7,767	2,431,094	2,275,752	15,534	2,291,286	(139,808)
324.00 Accessory Electric Equipment	50,017,128	1,425,488	5,002	1,430,490	1,345,461	5,002	1,350,463	(80,027)
325.00 Miscellaneous Power Plant Equipment	26,812,162	967,919	5,362	973,281	817,771	5,362	823,133	(150,148)
Total Palo Verde Unit 2	$471,841,386	$14,568,647	$40,808	$14,609,455	$13,855,374	$216,371	$14,071,745	($537,710)
Palo Verde Unit 3								
321.00 Structures and Improvements	$160,295,268	$4,039,441		$4,039,441	$3,750,909		$3,750,909	($288,532)
322.00 Reactor Plant Equipment	324,634,368	8,635,274	32,463	8,667,737	7,726,298	162,317	7,888,615	(779,122)
322.10 Steam Generators	25,412,774	742,053		742,053	584,494	5,083	589,577	(152,476)
323.00 Turbogenerator Units	144,937,168	3,942,291	14,494	3,956,785	3,507,479	14,494	3,521,973	(434,812)
324.00 Accessory Electric Equipment	89,475,454	2,335,309	8,948	2,344,257	2,093,726	8,948	2,102,674	(241,583)
325.00 Miscellaneous Power Plant Equipment	27,650,635	876,525	8,295	884,820	694,031	5,530	699,561	(185,259)
Total Palo Verde Unit 3	$772,405,667	$20,570,893	$64,200	$20,635,093	$18,356,937	$196,372	$18,553,309	($2,081,784)
Palo Verde Water Reclamation								
321.00 Structures and Improvements	$140,178,050	$3,728,736		$3,728,736	$3,981,057	$28,036	$4,009,093	$280,357
322.00 Reactor Plant Equipment	133,326	5,413	13	5,426	5,240	40	5,280	(146)
322.10 Steam Generators								
323.00 Turbogenerator Units	217,756	6,663	22	6,685	6,206	44	6,250	(435)
324.00 Accessory Electric Equipment								
325.00 Miscellaneous Power Plant Equipment	88,819	3,038	27	3,065	2,514	44	2,558	(507)
Total Palo Verde Water Reclamation	$140,617,951	$3,743,850	$62	$3,743,912	$3,995,017	$28,164	$4,023,181	$279,269
Palo Verde Common								
321.00 Structures and Improvements	$111,331,624	$2,905,755		$2,905,755	$2,939,155	$22,266	$2,961,421	$55,666
322.00 Reactor Plant Equipment	26,358,394	719,584	2,636	722,220	653,688	21,087	674,775	(47,445)
322.10 Steam Generators								
323.00 Turbogenerator Units	2,164,993	67,548	216	67,764	94,827	1,299	96,126	28,362
324.00 Accessory Electric Equipment	18,481,014	493,443	1,848	495,291	463,873	1,848	465,721	(29,570)
325.00 Miscellaneous Power Plant Equipment	52,710,304	1,734,169	15,813	1,749,982	1,576,038	31,626	1,607,664	(142,318)
Total Palo Verde Common	$211,046,329	$5,920,499	$20,513	$5,941,012	$5,727,581	$78,126	$5,805,707	($135,305)

ARIZONA PUBLIC SERVICE COMPANY Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
OTHER PRODUCTION (by Unit)								
Douglas CT								
341.00 Structures and Improvements	$49,075	$348	$15	$363	$2,915	$142	$3,057	$2,694
342.00 Fuel Holders, Products and Accessories	137,759	2,645	124	2,769	2,507	83	2,590	(179)
343.00 Prime Movers	1,101,449	7,820		7,820	8,041	441	8,482	662
344.00 Generators and Devices	551,765	662		662	3,862	166	4,028	3,366
345.00 Accessory Electric Equipment	353,277	3,144		3,144	3,462	247	3,709	565
346.00 Miscellaneous Power Plant Equipment	40,913	757		757	675	33	708	(49)
Total Douglas CT	$2,234,238	$15,376	$139	$15,515	$21,462	$1,112	$22,574	$7,059
Ocotillo CT Units 1-2								
341.00 Structures and Improvements	$434,488	$10,167	$521	$10,688	$8,777	$434	$9,211	($1,477)
342.00 Fuel Holders, Products and Accessories	719,859	15,549	792	16,341	13,893	648	14,541	(1,800)
343.00 Prime Movers	6,540,275	90,256		90,256	82,407	3,924	86,331	(3,925)
344.00 Generators and Devices	6,782,498	226,535		226,535	221,109	8,817	229,926	3,391
345.00 Accessory Electric Equipment	1,569,515	26,525		26,525	26,368	1,570	27,938	1,413
346.00 Miscellaneous Power Plant Equipment	558,648	11,005		11,005	9,888	447	10,335	(670)
Total Octillo CT Units 1-2	$16,605,283	$380,037	$1,313	$381,350	$362,442	$15,840	$378,282	($3,068)
Redhawk CC Units 1-2								
341.00 Structures and Improvements	$21,367,258	$570,506	$17,094	$587,600	$643,154	$89,742	$732,896	$145,296
342.00 Fuel Holders, Products and Accessories	1,512,990	40,397	1,210	41,607	52,349	2,572	54,921	13,314
343.00 Prime Movers	175,383,772	4,682,747	140,307	4,823,054	5,226,436	122,769	5,349,205	526,151
344.00 Generators and Devices	243,992,340	6,514,595	195,194	6,709,789	7,368,569	292,791	7,661,360	951,571
345.00 Accessory Electric Equipment	22,109,344	590,319	17,687	608,006	661,069	26,531	687,600	79,594
346.00 Miscellaneous Power Plant Equipment	693,357	18,513	555	19,068	22,673	1,179	23,852	4,784
Total Redhawk CC Units 1-2	$465,059,061	$12,417,077	$372,047	$12,789,124	$13,974,250	$535,584	$14,509,834	$1,720,710
Saguaro								
341.00 Structures and Improvements	$1,414,380	$65,769	$3,253	$69,022	$54,029	$2,687	$56,716	($12,306)
342.00 Fuel Holders, Products and Accessories	1,304,977	22,707	1,174	23,881	21,141	913	22,054	(1,827)
343.00 Prime Movers	8,624,812	132,401		132,401	118,642	5,751	124,393	(8,008)
344.00 Generators and Devices	32,512,372	926,972		926,972	1,007,027	50,115	1,057,142	130,170
345.00 Accessory Electric Equipment	1,698,713	24,454		24,454	22,990	1,287	24,277	(177)
346.00 Miscellaneous Power Plant Equipment	846,669	28,956		28,956	27,093	1,355	28,448	(508)
Total Saguaro	$46,401,923	$1,201,259	$4,427	$1,205,686	$1,250,922	$62,108	$1,313,030	$107,344

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Saguaro CT Units 1-2								
341.00 Structures and Improvements	$1,414,380	$65,769	$3,253	$69,022	$54,029	$2,687	$56,716	($12,306)
342.00 Fuel Holders, Products and Accessories	1,304,977	22,707	1,174	23,881	21,141	913	22,054	(1,827)
343.00 Prime Movers	7,983,905	114,968		114,968	99,799	4,790	104,589	(10,379)
344.00 Generators and Devices	4,487,988	164,709		164,709	183,110	8,078	191,188	26,479
345.00 Accessory Electric Equipment	1,576,160	21,121		21,121	19,387	1,103	20,490	(631)
346.00 Miscellaneous Power Plant Equipment	846,669	28,956		28,956	27,093	1,355	28,448	(508)
Total Saguaro CT Units 1-2	$17,614,079	$418,230	$4,427	$422,657	$404,559	$18,926	$423,485	$828
Saguaro CT Unit 3								
341.00 Structures and Improvements								
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	640,907	17,433		17,433	18,843	961	19,804	2,371
344.00 Generators and Devices	28,024,384	762,263		762,263	823,917	42,037	865,954	103,691
345.00 Accessory Electric Equipment	122,553	3,333		3,333	3,603	184	3,787	454
346.00 Miscellaneous Power Plant Equipment								
Total Saguaro CT Unit 3	$28,787,844	$783,029		$783,029	$846,363	$43,182	$889,545	$106,516
Solar Units								
341.00 Structures and Improvements	$418,403	($44,267)	($42)	($44,309)	$2,176	$84	$2,260	$46,569
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices	15,334,956	926,231		926,231	857,224	47,538	904,762	(21,469)
345.00 Accessory Electric Equipment	166,635	10,498		10,498	8,932	450	9,382	(1,116)
346.00 Miscellaneous Power Plant Equipment								
Total Solar Units	$15,919,994	$892,462	($42)	$892,420	$868,332	$48,072	$916,404	$23,984
Sundance								
341.00 Structures and Improvements	$12,482,674	$242,164		$242,164	$275,867	$13,731	$289,598	$47,434
342.00 Fuel Holders, Products and Accessories	4,254,044	82,103		82,103	93,164	4,679	97,843	15,740
343.00 Prime Movers	229,648,056	4,455,172		4,455,172	5,052,257	252,613	5,304,870	849,698
344.00 Generators and Devices	297,855	6,374		6,374	8,995	447	9,442	3,068
345.00 Accessory Electric Equipment	25,914,410	497,557		497,557	567,526	28,506	596,032	98,475
346.00 Miscellaneous Power Plant Equipment	1,220,859	23,440		23,440	26,737	1,343	28,080	4,640
Total Sun Dance	$273,817,898	$5,306,810		$5,306,810	$6,024,546	$301,319	$6,325,865	$1,019,055

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
West Phoenix								
341.00 Structures and Improvements	$23,501,929	$575,387	$28,802	$604,189	$672,642	$36,377	$709,019	$104,830
342.00 Fuel Holders, Products and Accessories	26,801,921	758,448	39,127	797,575	941,893	47,689	989,582	192,007
343.00 Prime Movers	164,814,870	4,047,428	82,665	4,130,093	4,901,928	190,425	5,092,353	962,260
344.00 Generators and Devices	231,622,565	6,769,635	143,696	6,913,331	7,724,372	357,165	8,081,537	1,168,206
345.00 Accessory Electric Equipment	29,999,485	832,931	16,278	849,209	1,009,714	49,108	1,058,822	209,613
346.00 Miscellaneous Power Plant Equipment	3,871,189	108,943	58	109,001	120,553	6,299	126,852	17,851
Total West Phoenix	$480,611,959	$13,092,772	$310,626	$13,403,398	$15,371,102	$687,063	$16,058,165	$2,654,767
West Phoenix CC Units 1-3								
341.00 Structures and Improvements	$3,307,106	$81,024	$3,969	$84,993	$132,615	$6,284	$138,899	$53,906
342.00 Fuel Holders, Products and Accessories	21,229,279	653,862	33,967	687,829	796,098	40,336	836,434	148,605
343.00 Prime Movers								
344.00 Generators and Devices	91,829,248	2,966,085	64,280	3,030,365	3,517,060	146,927	3,663,987	633,622
345.00 Accessory Electric Equipment	16,524,179	485,811		485,811	622,962	29,744	652,706	166,895
346.00 Miscellaneous Power Plant Equipment	2,760,231	70,662		70,662	82,255	4,416	86,671	16,009
Total West Phoenix CC Units 1-3	$135,650,043	$4,257,444	$102,216	$4,359,660	$5,150,990	$227,707	$5,378,697	$1,019,037
West Phoenix CC Unit 4								
341.00 Structures and Improvements	$4,524,163	$83,697	$4,072	$87,769	$137,535	$6,786	$144,321	$56,552
342.00 Fuel Holders, Products and Accessories	4,135,109	78,567	3,722	82,289	123,226	6,203	129,429	47,140
343.00 Prime Movers	54,739,557	1,067,421	21,896	1,089,317	1,631,239	82,109	1,713,348	624,031
344.00 Generators and Devices	15,261,009	383,051	7,631	390,682	460,882	24,418	485,300	94,618
345.00 Accessory Electric Equipment	59,871	1,245	60	1,305	1,946	96	2,042	737
346.00 Miscellaneous Power Plant Equipment	27,151	532	24	556	866	43	909	353
Total West Phoenix CC Unit 4	$78,746,860	$1,614,513	$37,405	$1,651,918	$2,355,694	$119,655	$2,475,349	$823,431
West Phoenix CC Unit 5								
341.00 Structures and Improvements	$10,804,474	$296,043	$15,126	$311,169	$326,295	$17,287	$343,582	$32,413
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	101,281,146	2,775,103	60,769	2,835,872	3,099,203	101,281	3,200,484	364,612
344.00 Generators and Devices	119,641,646	3,278,181	71,785	3,349,966	3,625,142	179,462	3,804,604	454,638
345.00 Accessory Electric Equipment	11,706,160	320,749	16,389	337,138	353,526	17,559	371,085	33,947
346.00 Miscellaneous Power Plant Equipment	24,203	663	34	697	770	39	809	112
Total West Phoenix CC Unit 5	$243,457,629	$6,670,739	$164,103	$6,834,842	$7,404,936	$315,628	$7,720,564	$885,722

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Component Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/07 Investment	Present 2008 Annualized Accrual			Proposed 2008 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
West Phoenix CT Units 1-2								
341.00 Structures and Improvements	$510,951	$7,920	$409	$8,329	$6,949	$358	$7,307	($1,022)
342.00 Fuel Holders, Products and Accessories	1,437,533	26,019	1,438	27,457	22,569	1,150	23,719	(3,738)
343.00 Prime Movers	8,794,167	204,904		204,904	171,486	7,035	178,521	(26,383)
344.00 Generators and Devices	4,890,662	142,318		142,318	121,288	6,358	127,646	(14,672)
345.00 Accessory Electric Equipment	1,709,275	25,126	(171)	24,955	31,280	1,709	32,989	8,034
346.00 Miscellaneous Power Plant Equipment	1,059,604	37,086		37,086	36,662	1,801	38,463	1,377
Total West Phoenix CT Units 1-2	$18,402,192	$443,373	$1,676	$445,049	$390,234	$18,411	$408,645	($36,404)
West Phoenix Common								
341.00 Structures and Improvements	$4,355,235	$106,703	$5,226	$111,929	$69,248	$5,662	$74,910	($37,019)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers								
344.00 Generators and Devices								
345.00 Accessory Electric Equipment								
346.00 Miscellaneous Power Plant Equipment								
Total West Phoenix Common	$4,355,235	$106,703	$5,226	$111,929	$69,248	$5,662	$74,910	($37,019)
Yucca CT Units 1-4								
341.00 Structures and Improvements	$537,719	$19,788	$1,022	$20,810	$19,250	$914	$20,164	($646)
342.00 Fuel Holders, Products and Accessories	3,244,987	29,529	1,298	30,827	26,284	1,298	27,582	(3,245)
343.00 Prime Movers	7,962,254	49,366		49,366	46,181	2,389	48,570	(796)
344.00 Generators and Devices	6,526,095	90,713		90,713	170,331	7,831	178,162	87,449
345.00 Accessory Electric Equipment	2,712,683	33,909	(271)	33,638	64,019	3,526	67,545	33,907
346.00 Miscellaneous Power Plant Equipment	561,193	10,158		10,158	13,300	617	13,917	3,759
Total Yucca CT Units 1-4	$21,544,931	$233,463	$2,049	$235,512	$339,365	$16,575	$355,940	$120,428

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$139,734,640	$78,506,917	56.18%	$72,700,698	52.03%	$82,949,668	59.36%
312.00 Boiler Plant Equipment	912,545,152	557,950,892	61.14%	478,527,492	52.44%	539,849,051	59.16%
314.00 Turbogenerator Units	226,414,540	121,604,753	53.71%	119,105,636	52.61%	133,746,291	59.07%
315.00 Accessory Electric Equipment	151,610,085	93,533,690	61.69%	82,402,958	54.35%	97,582,591	64.36%
316.00 Miscellaneous Power Plant Equipment	72,551,134	34,155,416	47.08%	28,825,080	39.73%	31,624,067	43.59%
Total Steam Production Plant	$1,502,855,551	$885,751,667	58.94%	$781,561,863	52.01%	$885,751,667	58.94%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$657,537,995	$339,111,694	51.57%	$324,169,797	49.30%	$347,130,605	52.79%
322.00 Reactor Plant Equipment	1,014,755,344	498,140,946	49.09%	477,351,149	47.04%	509,757,005	50.23%
322.10 Steam Generators	25,412,774	28,568,730	112.42%	12,648,885	49.77%	14,389,874	56.62%
323.00 Turbogenerator Units	346,650,191	176,153,884	50.82%	167,481,660	48.31%	179,976,757	51.92%
324.00 Accessory Electric Equipment	272,678,334	155,637,633	57.08%	142,388,437	52.22%	152,226,317	55.83%
325.00 Miscellaneous Power Plant Equipment	137,397,362	71,459,544	52.01%	60,705,918	44.18%	65,591,874	47.74%
Total Nuclear Production Plant	$2,454,432,000	$1,269,072,432	51.71%	$1,184,745,846	48.27%	$1,269,072,432	51.71%
OTHER PRODUCTION							
341.00 Structures and Improvements	$60,205,926	$16,421,287	27.28%	$9,317,283	15.48%	$14,486,466	24.06%
342.00 Fuel Holders, Products and Accessories	37,976,537	14,498,397	38.18%	11,453,036	30.16%	14,184,080	37.35%
343.00 Prime Movers	594,075,488	173,151,534	29.15%	94,958,951	15.98%	174,457,887	29.37%
344.00 Generators and Devices	537,620,446	107,900,504	20.07%	101,477,891	18.88%	109,824,494	20.43%
345.00 Accessory Electric Equipment	84,524,062	27,131,496	32.10%	16,457,720	19.47%	26,233,231	31.04%
346.00 Miscellaneous Power Plant Equipment	7,792,828	3,880,401	49.79%	2,982,502	38.27%	3,797,461	48.73%
Total Other Production Plant	$1,322,195,287	$342,983,619	25.94%	$236,647,385	17.90%	$342,983,619	25.94%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$95,935	$99,853	104.08%	$59,412	61.93%	$50,885	53.04%
353.00 Station Equipment	77,712,529	16,766,378	21.57%	21,092,918	27.14%	18,065,651	23.25%
354.00 Towers and Fixtures	1,329,316	1,074,973	80.87%	450,616	33.90%	385,943	29.03%
355.00 Poles and Fixtures	1,366,890	233,641	17.09%	152,301	11.14%	130,443	9.54%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
356.00 Overhead Conductors and Devices	1,947,677	656,915	33.73%	232,158	11.92%	198,838	10.21%
Total Transmission Plant	$82,452,347	$18,831,760	22.84%	$21,987,404	26.67%	$18,831,760	22.84%
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$38,266,283	$14,275,927	37.29%	$8,614,817	22.50%	$11,730,665	30.64%
362.00 Station Equipment	324,622,763	59,593,397	18.36%	45,912,871	14.14%	62,518,860	19.26%
364.01 Poles, Towers and Fixtures - Wood	306,109,637	101,129,426	33.04%	78,277,648	25.57%	106,589,484	34.82%
364.02 Poles, Towers and Fixtures - Steel	130,459,890	12,126,930	9.30%	11,665,673	8.94%	15,884,969	12.18%
365.00 Overhead Conductors and Devices	272,581,755	45,846,052	16.82%	32,630,387	11.97%	44,432,303	16.30%
366.00 Underground Conduit	577,756,928	47,506,402	8.22%	76,040,783	13.16%	103,543,580	17.92%
367.00 Underground Conductors and Devices	1,234,823,572	374,085,772	30.29%	270,028,250	21.87%	367,693,367	29.78%
368.00 Line Transformers	653,512,139	288,983,225	44.22%	132,392,505	20.26%	180,276,863	27.59%
369.00 Services	309,417,647	131,536,367	42.51%	71,257,042	23.03%	97,029,631	31.36%
370.01 Meters - Electronic	93,968,807	15,372,259	16.36%	64,099,292	68.21%	64,099,292	68.21%
370.02 Meters - Electromechanical	72,160,378	13,582,770	18.82%	71,805,549	99.51%	71,805,549	99.51%
370.03 Meters - AMI	14,033,538	270,885	1.93%	286,068	2.04%	389,535	2.78%
371.00 Installations on Customers' Premises	39,046,677	6,583,321	16.86%	4,110,303	10.53%	5,596,937	14.33%
373.00 Street Lighting and Signal Systems	70,437,334	33,846,588	48.05%	9,655,896	13.71%	13,148,287	18.67%
Total Distribution Plant	$4,137,217,348	$1,144,739,322	27.67%	$876,777,083	21.19%	$1,144,739,322	27.67%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$111,657,425	$45,610,118	40.85%	$28,099,287	25.17%	$34,919,532	31.27%
391.CM Office Furn. and Equip. - Computer	69,159,918	27,501,805	39.77%	29,025,879	41.97%	36,071,027	52.16%
392.EL Transportation Equipment - Electric Vehicles	1,698,104	1,552,831	91.45%	737,929	43.46%	917,039	54.00%
392.HD Transportation Equipment - Heavy Duty	3,626,209	2,827,101	77.96%	2,387,661	65.84%	2,967,193	81.83%
392.LD Transportation Equipment - Light Duty	14,285,978	9,658,129	67.61%	3,352,052	23.46%	4,165,660	29.16%
392.MD Transportation Equipment - Medium Duty	1,392,936	1,102,657	79.16%	858,126	61.61%	1,066,410	76.56%
392.TR Transportation Equipment - Trailers	4,428,889	3,881,670	87.64%	1,707,603	38.56%	2,122,072	47.91%
396.00 Power Operated Equipment	10,707,227	7,949,932	74.25%	5,902,464	55.13%	7,335,107	68.51%
397.00 Communication Equipment	120,998,470	38,294,638	31.65%	46,078,686	38.08%	57,262,883	47.33%
Total Depreciable	$337,955,156	$138,378,881	40.95%	$118,149,687	34.96%	$146,826,924	43.45%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$51,190,495	$26,023,597	50.84%	$22,597,761	44.14%	$22,597,761	44.14%
393.00 Stores Equipment	1,237,565	1,137,893	91.95%	1,225,532	99.03%	1,225,532	99.03%
394.00 Tools, Shop and Garage Equipment	20,539,378	7,754,732	37.76%	8,042,470	39.16%	8,042,470	39.16%
395.00 Laboratory Equipment	1,894,538	914,699	48.28%	1,283,869	67.77%	1,283,869	67.77%
398.00 Miscellaneous Equipment	10,510,399	7,841,669	74.61%	2,074,915	19.74%	2,074,915	19.74%
Total Amortizable	$85,372,375	$43,672,590	51.16%	$35,224,547	41.26%	$35,224,547	41.26%
Total General Plant	$423,327,531	$182,051,471	43.00%	$153,374,234	36.23%	$182,051,471	43.00%
TOTAL UTILITY	$9,922,480,064	$3,843,430,272	38.73%	$3,255,093,815	32.81%	$3,843,430,272	38.73%
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$57,025,813	$34,493,429	60.49%	$28,310,220	49.64%	$36,677,133	64.32%
312.00 Boiler Plant Equipment	350,284,053	212,374,741	60.63%	154,165,659	44.01%	199,246,774	56.88%
314.00 Turbogenerator Units	101,616,123	39,116,311	38.49%	36,958,850	36.37%	48,003,242	47.24%
315.00 Accessory Electric Equipment	89,687,352	55,943,828	62.38%	45,524,303	50.76%	58,637,757	65.38%
316.00 Miscellaneous Power Plant Equipment	22,758,920	11,113,530	48.83%	8,046,327	35.35%	10,476,934	46.03%
Total Cholla	$621,372,261	$353,041,839	56.82%	$273,005,358	43.94%	$353,041,839	56.82%
Cholla Unit 1							
311.00 Structures and Improvements	$3,648,903	$1,935,921	53.05%	$1,537,163	42.13%	$2,180,464	59.76%
312.00 Boiler Plant Equipment	68,193,466	21,322,436	31.27%	14,601,655	21.41%	20,712,429	30.37%
314.00 Turbogenerator Units	11,111,084	8,190,487	73.71%	6,154,619	55.39%	8,730,318	78.57%
315.00 Accessory Electric Equipment	7,508,911	4,081,961	54.36%	2,908,544	38.73%	4,125,766	54.94%
316.00 Miscellaneous Power Plant Equipment	2,432,224	1,745,276	71.76%	1,076,564	44.26%	1,527,105	62.79%
Total Cholla Unit 1	$92,894,588	$37,276,082	40.13%	$26,278,545	28.29%	$37,276,082	40.13%
Cholla Unit 2							
311.00 Structures and Improvements	$5,452,541	$2,822,417	51.76%	$2,323,414	42.61%	$2,999,942	55.02%
312.00 Boiler Plant Equipment	148,802,569	104,252,920	70.06%	76,083,724	51.13%	98,237,684	66.02%
314.00 Turbogenerator Units	37,854,762	14,847,695	39.22%	14,881,258	39.31%	19,214,363	50.76%
315.00 Accessory Electric Equipment	44,885,780	29,555,768	65.85%	24,078,418	53.64%	31,089,540	69.26%
316.00 Miscellaneous Power Plant Equipment	5,812,164	3,201,362	55.08%	2,430,827	41.82%	3,138,632	54.00%
Total Cholla Unit 2	$242,807,816	$154,680,162	63.70%	$119,797,641	49.34%	$154,680,162	63.70%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Cholla Unit 3							
311.00 Structures and Improvements	$9,819,620	$6,270,897	63.86%	$5,197,843	52.93%	$6,543,588	66.64%
312.00 Boiler Plant Equipment	106,408,931	71,923,029	67.59%	53,248,210	50.04%	67,034,407	63.00%
314.00 Turbogenerator Units	51,739,505	15,723,288	30.39%	15,572,338	30.10%	19,604,085	37.89%
315.00 Accessory Electric Equipment	30,765,519	19,536,300	63.50%	16,235,862	52.77%	20,439,399	66.44%
316.00 Miscellaneous Power Plant Equipment	4,593,291	2,599,312	56.59%	1,931,320	42.05%	2,431,347	52.93%
Total Cholla Unit 3	$203,326,866	$116,052,826	57.08%	$92,185,573	45.34%	$116,052,826	57.08%
Cholla Common							
311.00 Structures and Improvements	$38,104,749	$23,464,195	61.58%	$19,251,800	50.52%	$24,953,139	65.49%
312.00 Boiler Plant Equipment	26,879,087	14,876,354	55.35%	10,232,069	38.07%	13,262,253	49.34%
314.00 Turbogenerator Units	910,772	354,841	38.96%	350,636	38.50%	454,475	49.90%
315.00 Accessory Electric Equipment	6,527,142	2,769,798	42.44%	2,301,478	35.26%	2,983,051	45.70%
316.00 Miscellaneous Power Plant Equipment	9,921,241	3,567,581	35.96%	2,607,616	26.28%	3,379,851	34.07%
Total Cholla Common	$82,342,991	$45,032,769	54.69%	$34,743,600	42.19%	$45,032,769	54.69%
Four Corners							
311.00 Structures and Improvements	$48,283,791	$23,456,344	48.58%	$25,130,585	52.05%	$24,909,117	51.59%
312.00 Boiler Plant Equipment	353,157,905	212,976,210	60.31%	206,972,508	58.61%	210,904,149	59.72%
314.00 Turbogenerator Units	68,213,063	37,000,894	54.24%	39,099,333	57.32%	38,947,389	57.10%
315.00 Accessory Electric Equipment	33,335,936	19,297,778	57.89%	19,551,761	58.65%	19,687,574	59.06%
316.00 Miscellaneous Power Plant Equipment	24,153,428	10,320,330	42.73%	9,352,374	38.72%	8,603,327	35.62%
Total Four Corners	$527,144,123	$303,051,556	57.49%	$300,106,561	56.93%	$303,051,556	57.49%
Four Corners Units 1-3							
311.00 Structures and Improvements	$32,557,195	$14,669,628	45.06%	$17,191,196	52.80%	$16,234,064	49.86%
312.00 Boiler Plant Equipment	234,692,935	135,531,700	57.75%	140,523,707	59.88%	132,699,947	56.54%
314.00 Turbogenerator Units	49,894,597	26,846,609	53.81%	29,810,307	59.75%	28,150,596	56.42%
315.00 Accessory Electric Equipment	19,105,566	11,467,104	60.02%	12,233,462	64.03%	11,552,355	60.47%
316.00 Miscellaneous Power Plant Equipment	11,296,591	3,519,953	31.16%	3,598,375	31.85%	3,398,033	30.08%
Total Four Corners Units 1-3	$347,546,884	$192,034,994	55.25%	$203,357,047	58.51%	$192,034,994	55.25%
Four Corners Units 4-5							
311.00 Structures and Improvements	$11,035,183	$5,946,330	53.89%	$5,403,863	48.97%	$6,669,145	60.44%
312.00 Boiler Plant Equipment	103,280,404	73,869,963	71.52%	57,864,179	56.03%	71,412,727	69.14%
314.00 Turbogenerator Units	16,330,966	8,642,457	52.92%	7,783,003	47.66%	9,605,346	58.82%
315.00 Accessory Electric Equipment	10,081,177	5,764,341	57.18%	5,294,442	52.52%	6,534,104	64.81%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
316.00 Miscellaneous Power Plant Equipment	3,123,482	1,817,827	58.20%	1,474,380	47.20%	1,819,597	58.26%
Total Four Corners Units 4-5	$143,851,212	$96,040,918	66.76%	$77,819,867	54.10%	$96,040,918	66.76%
Four Corners Common							
311.00 Structures and Improvements	$4,691,413	$2,840,386	60.54%	$2,535,526	54.05%	$2,005,908	42.76%
312.00 Boiler Plant Equipment	15,184,566	3,574,546	23.54%	8,584,622	56.54%	6,791,476	44.73%
314.00 Turbogenerator Units	1,987,500	1,511,829	76.07%	1,506,023	75.77%	1,191,447	59.95%
315.00 Accessory Electric Equipment	4,149,193	2,066,333	49.80%	2,023,857	48.78%	1,601,116	38.59%
316.00 Miscellaneous Power Plant Equipment	9,733,355	4,982,550	51.19%	4,279,619	43.97%	3,385,697	34.78%
Total Four Corners Common	$35,746,027	$14,975,644	41.89%	$18,929,647	52.96%	$14,975,644	41.89%
Navajo Units 1-3							
311.00 Structures and Improvements	$27,580,268	$15,270,064	55.37%	$14,173,889	51.39%	$16,000,134	58.01%
312.00 Boiler Plant Equipment	161,702,139	90,446,486	55.93%	78,130,452	48.32%	88,197,224	54.54%
314.00 Turbogenerator Units	24,699,305	16,272,422	65.88%	15,261,571	61.79%	17,227,958	69.75%
315.00 Accessory Electric Equipment	20,805,398	13,320,318	64.02%	12,330,934	59.27%	13,919,721	66.90%
316.00 Miscellaneous Power Plant Equipment	16,797,235	7,793,865	46.40%	6,872,612	40.92%	7,758,118	46.19%
Total Navajo Units 1-3	$251,584,345	$143,103,155	56.88%	$126,769,458	50.39%	$143,103,155	56.88%
Ocotillo Units 1-2							
311.00 Structures and Improvements	$3,796,298	$2,763,260	72.79%	$2,822,409	74.35%	$2,776,719	73.14%
312.00 Boiler Plant Equipment	24,502,039	21,070,423	85.99%	21,146,093	86.30%	20,803,777	84.91%
314.00 Turbogenerator Units	15,372,486	13,469,282	87.62%	13,738,959	89.37%	13,516,552	87.93%
315.00 Accessory Electric Equipment	2,859,128	2,227,616	77.91%	2,336,835	81.73%	2,299,007	80.41%
316.00 Miscellaneous Power Plant Equipment	5,544,025	2,452,838	44.24%	2,629,937	47.44%	2,587,364	46.67%
Total Ocotillo Units 1-2	$52,073,976	$41,983,419	80.62%	$42,674,234	81.95%	$41,983,419	80.62%
Saguaro Units 1-2							
311.00 Structures and Improvements	$3,048,470	$2,523,820	82.79%	$2,263,594	74.25%	$2,586,566	84.85%
312.00 Boiler Plant Equipment	22,899,016	21,083,032	92.07%	18,112,780	79.10%	20,697,127	90.38%
314.00 Turbogenerator Units	16,513,563	15,745,844	95.35%	14,046,923	85.06%	16,051,150	97.20%
315.00 Accessory Electric Equipment	4,922,271	2,744,150	55.75%	2,659,125	54.02%	3,038,532	61.73%
316.00 Miscellaneous Power Plant Equipment	3,297,526	2,474,853	75.05%	1,923,830	58.34%	2,198,324	66.67%
Total Saguaro Units 1-2	$50,680,846	$44,571,699	87.95%	$39,006,252	76.96%	$44,571,699	87.95%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$657,537,995	$339,111,694	51.57%	$324,169,797	49.30%	$347,130,605	52.79%
322.00 Reactor Plant Equipment	1,014,755,344	498,140,946	49.09%	477,351,149	47.04%	509,757,005	50.23%
322.10 Steam Generators	25,412,774	28,568,730	112.42%	12,648,885	49.77%	14,389,874	56.62%
323.00 Turbogenerator Units	346,650,191	176,153,884	50.82%	167,481,660	48.31%	179,976,757	51.92%
324.00 Accessory Electric Equipment	272,678,334	155,637,633	57.08%	142,388,437	52.22%	152,226,317	55.83%
325.00 Miscellaneous Power Plant Equipment	137,397,362	71,459,544	52.01%	60,705,918	44.18%	65,591,874	47.74%
Total Palo Verde	$2,454,432,000	$1,269,072,432	51.71%	$1,184,745,846	48.27%	$1,269,072,432	51.71%
Palo Verde Unit 1							
321.00 Structures and Improvements	$155,161,288	$89,568,402	57.73%	$85,698,941	55.23%	$88,661,645	57.14%
322.00 Reactor Plant Equipment	436,859,649	210,732,824	48.24%	206,449,625	47.26%	213,586,807	48.89%
322.10 Steam Generators							
323.00 Turbogenerator Units	121,659,550	60,019,824	49.33%	60,426,138	49.67%	62,515,134	51.39%
324.00 Accessory Electric Equipment	114,704,738	68,728,125	59.92%	63,638,886	55.48%	65,838,950	57.40%
325.00 Miscellaneous Power Plant Equipment	30,135,442	17,696,944	58.72%	15,604,132	51.78%	16,143,583	53.57%
Total Palo Verde Unit 1	$858,520,667	$446,746,119	52.04%	$431,817,722	50.30%	$446,746,119	52.04%
Palo Verde Unit 2							
321.00 Structures and Improvements	$90,571,765	$48,360,282	53.39%	$48,317,176	53.35%	$49,447,483	54.59%
322.00 Reactor Plant Equipment	226,769,607	104,218,716	45.96%	102,846,127	45.35%	105,252,055	46.41%
322.10 Steam Generators							
323.00 Turbogenerator Units	77,670,724	39,386,721	50.71%	37,749,929	48.60%	38,633,031	49.74%
324.00 Accessory Electric Equipment	50,017,128	27,720,383	55.42%	26,386,629	52.76%	27,003,904	53.99%
325.00 Miscellaneous Power Plant Equipment	26,812,162	13,444,271	50.14%	12,501,448	46.63%	12,793,900	47.72%
Total Palo Verde Unit 2	$471,841,386	$233,130,373	49.41%	$227,801,310	48.28%	$233,130,373	49.41%
Palo Verde Unit 3							
321.00 Structures and Improvements	$160,295,268	$84,667,877	52.82%	$78,536,748	49.00%	$89,346,523	55.74%
322.00 Reactor Plant Equipment	324,634,368	169,358,319	52.17%	155,731,123	47.97%	177,165,909	54.57%
322.10 Steam Generators	25,412,774	28,568,730	112.42%	12,648,885	49.77%	14,389,874	56.62%
323.00 Turbogenerator Units	144,937,168	76,613,652	52.86%	68,905,749	47.54%	78,389,916	54.09%
324.00 Accessory Electric Equipment	89,475,454	49,510,002	55.33%	43,706,312	48.85%	49,722,036	55.57%
325.00 Miscellaneous Power Plant Equipment	27,650,635	14,699,800	53.16%	12,661,409	45.79%	14,404,122	52.09%
Total Palo Verde Unit 3	$772,405,667	$423,418,380	54.82%	$372,190,227	48.19%	$423,418,380	54.82%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$140,178,050	$64,373,500	45.92%	$62,077,737	44.28%	$64,385,491	45.93%
322.00 Reactor Plant Equipment	133,326	33,922	25.44%	32,724	24.54%	33,941	25.46%
322.10 Steam Generators							
323.00 Turbogenerator Units	217,756	108,106	49.65%	96,062	44.11%	99,633	45.75%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	88,819	43,946	49.48%	38,960	43.86%	40,409	45.50%
Total Palo Verde Water Reclamation	$140,617,951	$64,559,473	45.91%	$62,245,482	44.27%	$64,559,473	45.91%
Palo Verde Common							
321.00 Structures and Improvements	$111,331,624	$52,141,633	46.83%	$49,539,195	44.50%	$55,289,463	49.66%
322.00 Reactor Plant Equipment	26,358,394	13,797,166	52.34%	12,291,549	46.63%	13,718,293	52.05%
322.10 Steam Generators							
323.00 Turbogenerator Units	2,164,993	25,582	1.18%	303,783	14.03%	339,044	15.66%
324.00 Accessory Electric Equipment	18,481,014	9,679,124	52.37%	8,656,610	46.84%	9,661,427	52.28%
325.00 Miscellaneous Power Plant Equipment	52,710,304	25,574,583	48.52%	19,899,968	37.75%	22,209,860	42.14%
Total Palo Verde Common	$211,046,329	$101,218,087	47.96%	$90,691,106	42.97%	$101,218,087	47.96%
OTHER PRODUCTION (by Unit)							
Douglas CT							
341.00 Structures and Improvements	$49,075	$5,113	10.42%	$11,210	22.84%	$13,912	28.35%
342.00 Fuel Holders, Products and Accessories	137,759	120,695	87.61%	90,859	65.96%	112,755	81.85%
343.00 Prime Movers	1,101,449	1,031,081	93.61%	848,333	77.02%	1,052,768	95.58%
344.00 Generators and Devices	551,765	548,657	99.44%	426,885	77.37%	529,758	96.01%
345.00 Accessory Electric Equipment	353,277	329,052	93.14%	262,319	74.25%	325,534	92.15%
346.00 Miscellaneous Power Plant Equipment	40,913	34,389	84.05%	27,606	67.48%	34,259	83.74%
Total Douglas CT	$2,234,238	$2,068,986	92.60%	$1,667,214	74.62%	$2,068,986	92.60%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$434,488	$355,977	81.93%	$283,322	65.21%	$343,108	78.97%
342.00 Fuel Holders, Products and Accessories	719,859	610,704	84.84%	476,387	66.18%	576,914	80.14%
343.00 Prime Movers	6,540,275	5,708,052	87.28%	4,793,541	73.29%	5,805,073	88.76%
344.00 Generators and Devices	6,782,498	4,351,003	64.15%	3,546,278	52.29%	4,294,612	63.32%
345.00 Accessory Electric Equipment	1,569,515	1,297,317	82.66%	1,076,875	68.61%	1,304,117	83.09%
346.00 Miscellaneous Power Plant Equipment	558,648	460,378	82.41%	379,520	67.94%	459,606	82.27%
Total Octillo CT Units 1-2	$16,605,283	$12,783,430	76.98%	$10,555,922	63.57%	$12,783,430	76.98%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$21,367,258	$3,684,110	17.24%	$1,484,871	6.95%	$1,627,958	7.62%
342.00 Fuel Holders, Products and Accessories	1,512,990	22,980	1.52%	25,854	1.71%	28,345	1.87%
343.00 Prime Movers	175,383,772	29,215,658	16.66%	29,272,008	16.69%	32,092,760	18.30%
344.00 Generators and Devices	243,992,340	38,842,307	15.92%	34,910,421	14.31%	38,274,510	15.69%
345.00 Accessory Electric Equipment	22,109,344	3,946,360	17.85%	3,340,042	15.11%	3,661,900	16.56%
346.00 Miscellaneous Power Plant Equipment	693,357	24,833	3.58%	46,311	6.68%	50,774	7.32%
Total Redhawk CC Units 1-2	$465,059,061	$75,736,248	16.29%	$69,079,507	14.85%	$75,736,248	16.29%
Saguaro							
341.00 Structures and Improvements	$1,414,380	$809,985	57.27%	$646,021	45.68%	$787,631	55.69%
342.00 Fuel Holders, Products and Accessories	1,304,977	1,162,002	89.04%	901,680	69.10%	1,099,331	84.24%
343.00 Prime Movers	8,624,812	7,112,933	82.47%	5,926,011	68.71%	7,210,439	83.60%
344.00 Generators and Devices	32,512,372	7,215,937	22.19%	6,422,179	19.75%	7,192,859	22.12%
345.00 Accessory Electric Equipment	1,698,713	1,414,927	83.29%	1,170,591	68.91%	1,424,401	83.85%
346.00 Miscellaneous Power Plant Equipment	846,669	538,011	63.54%	442,200	52.23%	539,132	63.68%
Total Saguaro	$46,401,923	$18,253,793	39.34%	$15,508,682	33.42%	$18,253,793	39.34%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$1,414,380	$809,985	57.27%	$646,021	45.68%	$787,631	55.69%
342.00 Fuel Holders, Products and Accessories	1,304,977	1,162,002	89.04%	901,680	69.10%	1,099,331	84.24%
343.00 Prime Movers	7,983,905	7,002,416	87.71%	5,823,391	72.94%	7,099,894	88.93%
344.00 Generators and Devices	4,487,988	2,382,225	53.08%	1,935,016	43.12%	2,359,177	52.57%
345.00 Accessory Electric Equipment	1,576,160	1,393,790	88.43%	1,150,968	73.02%	1,403,263	89.03%
346.00 Miscellaneous Power Plant Equipment	846,669	538,011	63.54%	442,200	52.23%	539,132	63.68%
Total Saguaro CT Units 1-2	$17,614,079	$13,288,428	75.44%	$10,899,276	61.88%	$13,288,428	75.44%
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	640,907	110,517	17.24%	102,620	16.01%	110,544	17.25%
344.00 Generators and Devices	28,024,384	4,833,712	17.25%	4,487,163	16.01%	4,833,683	17.25%
345.00 Accessory Electric Equipment	122,553	21,137	17.25%	19,623	16.01%	21,138	17.25%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	$28,787,844	$4,965,365	17.25%	$4,609,405	16.01%	$4,965,365	17.25%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Solar Units							
341.00 Structures and Improvements	$418,403	$407,064	97.29%	$341,244	81.56%	$432,136	103.28%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	15,334,956	11,176,372	72.88%	8,800,595	57.39%	11,144,691	72.68%
345.00 Accessory Electric Equipment	166,635	119,792	71.89%	99,815	59.90%	126,402	75.86%
346.00 Miscellaneous Power Plant Equipment							
Total Solar Units	$15,919,994	$11,703,229	73.51%	$9,241,654	58.05%	$11,703,229	73.51%
Sundance							
341.00 Structures and Improvements	$12,482,674	$4,812,815	38.56%	$977,674	7.83%	$4,882,194	39.11%
342.00 Fuel Holders, Products and Accessories	4,254,044	1,691,695	39.77%	337,223	7.93%	1,683,983	39.59%
343.00 Prime Movers	229,648,056	90,437,084	39.38%	18,131,880	7.90%	90,544,865	39.43%
344.00 Generators and Devices	297,855	21,555	7.24%	8,981	3.02%	44,851	15.06%
345.00 Accessory Electric Equipment	25,914,410	10,373,945	40.03%	2,054,263	7.93%	10,258,339	39.59%
346.00 Miscellaneous Power Plant Equipment	1,220,859	560,420	45.90%	96,779	7.93%	483,283	39.59%
Total Sun Dance	$273,817,898	$107,897,514	39.40%	$21,606,800	7.89%	$107,897,514	39.40%
West Phoenix							
341.00 Structures and Improvements	$23,501,929	$6,006,163	25.56%	$5,324,563	22.66%	$6,082,871	25.88%
342.00 Fuel Holders, Products and Accessories	26,801,921	7,690,412	28.69%	7,214,397	26.92%	7,614,536	28.41%
343.00 Prime Movers	164,814,870	32,066,539	19.46%	29,898,008	18.14%	29,988,912	18.20%
344.00 Generators and Devices	231,622,565	40,949,999	17.68%	43,708,187	18.87%	43,684,271	18.86%
345.00 Accessory Electric Equipment	29,999,485	7,728,272	25.76%	6,870,399	22.90%	7,113,845	23.71%
346.00 Miscellaneous Power Plant Equipment	3,871,189	1,855,680	47.94%	1,662,392	42.94%	1,812,631	46.82%
Total West Phoenix	$480,611,959	$96,297,065	20.04%	$94,677,947	19.70%	$96,297,065	20.04%
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$3,307,106	$327,241	9.90%	$674,440	20.39%	$696,491	21.06%
342.00 Fuel Holders, Products and Accessories	21,229,279	5,637,343	26.55%	5,429,147	25.57%	5,606,657	26.41%
343.00 Prime Movers							
344.00 Generators and Devices	91,829,248	23,244,477	25.31%	22,499,977	24.50%	23,235,630	25.30%
345.00 Accessory Electric Equipment	16,524,179	4,591,552	27.79%	4,181,033	25.30%	4,317,734	26.13%
346.00 Miscellaneous Power Plant Equipment	2,760,231	1,223,950	44.34%	1,131,070	40.98%	1,168,051	42.32%
Total West Phoenix CC Units 1-3	$135,650,043	$35,024,563	25.82%	$33,915,667	25.00%	$35,024,563	25.82%

ARIZONA PUBLIC SERVICE COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$4,524,163	$733,350	16.21%	$776,781	17.17%	$783,430	17.32%
342.00 Fuel Holders, Products and Accessories	4,135,109	786,677	19.02%	783,660	18.95%	790,367	19.11%
343.00 Prime Movers	54,739,557	10,288,463	18.80%	10,373,897	18.95%	10,462,691	19.11%
344.00 Generators and Devices	15,261,009	2,918,063	19.12%	2,663,885	17.46%	2,686,686	17.60%
345.00 Accessory Electric Equipment	59,871	4,943	8.26%	6,703	11.20%	6,761	11.29%
346.00 Miscellaneous Power Plant Equipment	27,151	1,933	7.12%	3,464	12.76%	3,494	12.87%
Total West Phoenix CC Unit 4	$78,746,860	$14,733,429	18.71%	$14,608,391	18.55%	$14,733,429	18.71%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$10,804,474	$1,612,125	14.92%	$1,412,583	13.07%	$1,284,518	11.89%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	101,281,146	14,863,314	14.68%	13,737,228	13.56%	12,491,809	12.33%
344.00 Generators and Devices	119,641,646	11,130,509	9.30%	15,609,161	13.05%	14,194,032	11.86%
345.00 Accessory Electric Equipment	11,706,160	1,765,482	15.08%	1,540,100	13.16%	1,400,475	11.96%
346.00 Miscellaneous Power Plant Equipment	24,203	1,085	4.48%	1,848	7.64%	1,680	6.94%
Total West Phoenix CC Unit 5	$243,457,629	$29,372,514	12.06%	$32,300,920	13.27%	$29,372,514	12.06%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$510,951	$461,817	90.38%	$367,563	71.94%	$446,801	87.45%
342.00 Fuel Holders, Products and Accessories	1,437,533	1,266,392	88.09%	1,001,590	69.67%	1,217,512	84.69%
343.00 Prime Movers	8,794,167	6,914,762	78.63%	5,786,883	65.80%	7,034,412	79.99%
344.00 Generators and Devices	4,890,662	3,656,950	74.77%	2,935,164	60.02%	3,567,922	72.95%
345.00 Accessory Electric Equipment	1,709,275	1,366,295	79.93%	1,142,563	66.84%	1,388,875	81.26%
346.00 Miscellaneous Power Plant Equipment	1,059,604	628,712	59.33%	526,010	49.64%	639,406	60.34%
Total West Phoenix CT Units 1-2	$18,402,192	$14,294,928	77.68%	$11,759,772	63.90%	$14,294,928	77.68%
West Phoenix Common							
341.00 Structures and Improvements	$4,355,235	$2,871,631	65.94%	$2,093,197	48.06%	$2,871,631	65.94%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices							
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total West Phoenix Common	$4,355,235	$2,871,631	65.94%	$2,093,197	48.06%	$2,871,631	65.94%

Statement C

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2007

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Yucca CT Units 1-4							
341.00 Structures and Improvements	$537,719	$340,060	63.24%	$248,378	46.19%	$316,656	58.89%
342.00 Fuel Holders, Products and Accessories	3,244,987	3,199,909	98.61%	2,406,637	74.16%	3,068,216	94.55%
343.00 Prime Movers	7,962,254	7,580,186	95.20%	6,089,171	76.48%	7,763,071	97.50%
344.00 Generators and Devices	6,526,095	4,794,676	73.47%	3,654,365	56.00%	4,658,942	71.39%
345.00 Accessory Electric Equipment	2,712,683	1,921,831	70.85%	1,583,415	58.37%	2,018,692	74.42%
346.00 Miscellaneous Power Plant Equipment	561,193	406,691	72.47%	327,693	58.39%	417,776	74.44%
Total Yucca CT Units 1-4	$21,544,931	$18,243,354	84.68%	$14,309,659	66.42%	$18,243,354	84.68%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$139,734,640	$73,595,382	52.67%	$9,354,287	6.69%	$82,949,668	59.36%
312.00 Boiler Plant Equipment	912,545,152	478,424,528	52.43%	61,424,523	6.73%	539,849,051	59.16%
314.00 Turbogenerator Units	226,414,540	114,517,898	50.58%	19,228,393	8.49%	133,746,291	59.07%
315.00 Accessory Electric Equipment	151,610,085	86,890,547	57.31%	10,692,044	7.05%	97,582,591	64.36%
316.00 Miscellaneous Power Plant Equipment	72,551,134	27,666,020	38.13%	3,958,046	5.46%	31,624,067	43.59%
Total Steam Production Plant	$1,502,855,551	$781,094,375	51.97%	$104,657,293	6.96%	$885,751,667	58.94%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$657,537,995	$346,957,936	52.77%	$172,669	0.03%	$347,130,605	52.79%
322.00 Reactor Plant Equipment	1,014,755,344	512,819,717	50.54%	(3,062,712)	-0.30%	509,757,005	50.23%
322.10 Steam Generators	25,412,774	14,289,845	56.23%	100,029	0.39%	14,389,874	56.62%
323.00 Turbogenerator Units	346,650,191	180,079,211	51.95%	(102,454)	-0.03%	179,976,757	51.92%
324.00 Accessory Electric Equipment	272,678,334	152,073,334	55.77%	152,983	0.06%	152,226,317	55.83%
325.00 Miscellaneous Power Plant Equipment	137,397,362	66,253,882	48.22%	(662,009)	-0.48%	65,591,874	47.74%
Total Nuclear Production Plant	$2,454,432,000	$1,272,473,925	51.84%	($3,401,492)	-0.14%	$1,269,072,432	51.71%
OTHER PRODUCTION							
341.00 Structures and Improvements	$60,205,926	$15,387,899	25.56%	($901,432)	-1.50%	$14,486,466	24.06%
342.00 Fuel Holders, Products and Accessories	37,976,537	13,504,459	35.56%	679,620	1.79%	14,184,080	37.35%
343.00 Prime Movers	594,075,488	161,201,523	27.13%	13,256,364	2.23%	174,457,887	29.37%
344.00 Generators and Devices	537,620,446	102,272,416	19.02%	7,552,078	1.40%	109,824,494	20.43%
345.00 Accessory Electric Equipment	84,524,062	24,812,961	29.36%	1,420,270	1.68%	26,233,231	31.04%
346.00 Miscellaneous Power Plant Equipment	7,792,828	3,622,275	46.48%	175,186	2.25%	3,797,461	48.73%
Total Other Production Plant	$1,322,195,287	$320,801,533	24.26%	$22,182,086	1.68%	$342,983,619	25.94%
TRANSMISSION PLANT							
352.02 Structures and Improvements	$95,935	$50,885	53.04%			$50,885	53.04%
353.00 Station Equipment	77,712,529	18,065,651	23.25%			18,065,651	23.25%
354.00 Towers and Fixtures	1,329,316	385,943	29.03%			385,943	29.03%
355.00 Poles and Fixtures	1,366,890	108,702	7.95%	21,740	1.59%	130,443	9.54%
356.00 Overhead Conductors and Devices	1,947,677	271,248	13.93%	(72,409)	-3.72%	198,838	10.21%
Total Transmission Plant	$82,452,347	$18,882,429	22.90%	($50,669)	-0.06%	$18,831,760	22.84%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$38,286,283	$11,015,420	28.77%	$715,245	1.87%	$11,730,665	30.64%
362.00 Station Equipment	324,622,763	69,465,400	21.40%	(6,946,540)	-2.14%	62,518,860	19.26%
364.01 Poles, Towers and Fixtures - Wood	306,109,637	87,395,389	28.55%	19,194,095	6.27%	106,589,484	34.82%
364.02 Poles, Towers and Fixtures - Steel	130,459,890	16,204,812	12.42%	(319,842)	-0.25%	15,884,969	12.18%
365.00 Overhead Conductors and Devices	272,581,755	48,652,519	17.85%	(4,220,216)	-1.55%	44,432,303	16.30%
366.00 Underground Conduit	577,756,928	98,612,933	17.07%	4,930,647	0.85%	103,543,580	17.92%
367.00 Underground Conductors and Devices	1,234,823,572	339,963,381	27.53%	27,729,986	2.25%	367,693,367	29.78%
368.00 Line Transformers	653,512,139	166,872,215	25.53%	13,404,648	2.05%	180,276,863	27.59%
369.00 Services	309,417,647	97,029,631	31.36%			97,029,631	31.36%
370.01 Meters - Electronic	93,968,807	64,099,292	68.21%			64,099,292	68.21%
370.02 Meters - Electromechanical	72,160,378	71,805,549	99.51%			71,805,549	99.51%
370.03 Meters - AMI	14,033,538	389,535	2.78%			389,535	2.78%
371.00 Installations on Customers' Premises	39,046,677	5,348,962	13.70%	247,974	0.64%	5,596,937	14.33%
373.00 Street Lighting and Signal Systems	70,437,334	11,260,372	15.99%	1,887,915	2.68%	13,148,287	18.67%
Total Distribution Plant	$4,137,217,348	$1,088,115,411	26.30%	$56,623,911	1.37%	$1,144,739,322	27.67%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$111,657,425	$33,557,273	30.05%	$1,362,259	1.22%	$34,919,532	31.27%
391.CM Office Furn. and Equip. - Computer	69,159,918	36,120,852	52.23%	(49,826)	-0.07%	36,071,027	52.16%
392.EL Transportation Equipment - Electric Vehicles	1,698,104	918,231	54.07%	(1,192)	-0.07%	917,039	54.00%
392.HD Transportation Equipment - Heavy Duty	3,626,209	3,012,024	83.06%	(44,830)	-1.24%	2,967,193	81.83%
392.LD Transportation Equipment - Light Duty	14,285,978	4,669,890	32.69%	(504,230)	-3.53%	4,165,660	29.16%
392.MD Transportation Equipment - Medium Duty	1,392,936	1,066,410	76.56%			1,066,410	76.56%
392.TR Transportation Equipment - Trailers	4,428,889	2,122,072	47.91%			2,122,072	47.91%
396.00 Power Operated Equipment	10,707,227	7,561,966	70.62%	(226,859)	-2.12%	7,335,107	68.51%
397.00 Communication Equipment	120,998,470	57,262,883	47.33%			57,262,883	47.33%
Total Depreciable	$337,955,156	$146,291,602	43.29%	$535,322	0.16%	$146,826,924	43.45%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$51,190,495	$22,597,761	44.14%			$22,597,761	44.14%
393.00 Stores Equipment	1,237,565	1,225,532	99.03%			1,225,532	99.03%
394.00 Tools, Shop and Garage Equipment	20,539,378	8,042,470	39.16%			8,042,470	39.16%
395.00 Laboratory Equipment	1,894,538	1,283,869	67.77%			1,283,869	67.77%
398.00 Miscellaneous Equipment	10,510,399	2,074,915	19.74%			2,074,915	19.74%
Total Amortizable	$85,372,375	$35,224,547	41.26%			$35,224,547	41.26%
Total General Plant	$423,327,531	$181,516,149	42.88%	$535,322	0.13%	$182,051,471	43.00%
TOTAL UTILITY	$9,922,480,064	$3,662,883,821	36.92%	$180,546,451	1.82%	$3,843,430,272	38.73%
STEAM PRODUCTION (by Unit)							
Cholla							
311.00 Structures and Improvements	$57,025,813	$32,974,937	57.82%	$3,702,195	6.49%	$36,677,133	64.32%
312.00 Boiler Plant Equipment	350,284,053	180,060,286	51.40%	19,186,488	5.48%	199,246,774	56.88%
314.00 Turbogenerator Units	101,616,123	41,976,212	41.31%	6,027,030	5.93%	48,003,242	47.24%
315.00 Accessory Electric Equipment	89,687,352	52,889,447	58.97%	5,748,310	6.41%	58,637,757	65.38%
316.00 Miscellaneous Power Plant Equipment	22,758,920	9,485,365	41.68%	991,569	4.36%	10,476,934	46.03%
Total Cholla	$621,372,261	$317,386,246	51.08%	$35,655,593	5.74%	$353,041,839	56.82%
Cholla Unit 1							
311.00 Structures and Improvements	$3,648,903	$1,984,359	54.38%	$196,105	5.37%	$2,180,464	59.76%
312.00 Boiler Plant Equipment	68,193,466	19,058,644	27.95%	1,653,785	2.43%	20,712,429	30.37%
314.00 Turbogenerator Units	11,111,084	7,929,623	71.37%	800,696	7.21%	8,730,318	78.57%
315.00 Accessory Electric Equipment	7,508,911	3,764,385	50.13%	361,381	4.81%	4,125,766	54.94%
316.00 Miscellaneous Power Plant Equipment	2,432,224	1,389,540	57.13%	137,564	5.66%	1,527,105	62.79%
Total Cholla Unit 1	$92,894,588	$34,126,552	36.74%	$3,149,530	3.39%	$37,276,082	40.13%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Cholla Unit 2							
311.00 Structures and Improvements	$5,452,541	$2,738,245	50.22%	$261,697	4.80%	$2,999,942	55.02%
312.00 Boiler Plant Equipment	148,802,569	89,505,504	60.15%	8,732,180	5.87%	98,237,684	66.02%
314.00 Turbogenerator Units	37,854,762	17,208,495	45.46%	2,005,868	5.30%	19,214,363	50.76%
315.00 Accessory Electric Equipment	44,885,780	28,340,511	63.14%	2,749,030	6.12%	31,089,540	69.26%
316.00 Miscellaneous Power Plant Equipment	5,812,164	2,865,952	49.31%	272,679	4.69%	3,138,632	54.00%
Total Cholla Unit 2	$242,807,816	$140,658,707	57.93%	$14,021,455	5.77%	$154,680,162	63.70%
Cholla Unit 3							
311.00 Structures and Improvements	$9,819,620	$5,816,522	59.23%	$727,065	7.40%	$6,543,588	66.64%
312.00 Boiler Plant Equipment	106,408,931	59,349,493	55.77%	7,684,915	7.22%	67,034,407	63.00%
314.00 Turbogenerator Units	51,739,505	16,458,078	31.81%	3,146,007	6.08%	19,604,085	37.89%
315.00 Accessory Electric Equipment	30,765,519	18,103,985	58.85%	2,335,414	7.59%	20,439,399	66.44%
316.00 Miscellaneous Power Plant Equipment	4,593,291	2,154,243	46.90%	277,104	6.03%	2,431,347	52.93%
Total Cholla Unit 3	$203,326,866	$101,882,322	50.11%	$14,170,504	6.97%	$116,052,826	57.08%
Cholla Common							
311.00 Structures and Improvements	$38,104,749	$22,435,810	58.88%	$2,517,328	6.61%	$24,953,139	65.49%
312.00 Boiler Plant Equipment	26,879,087	12,146,645	45.19%	1,115,608	4.15%	13,262,253	49.34%
314.00 Turbogenerator Units	910,772	380,016	41.72%	74,460	8.18%	454,475	49.90%
315.00 Accessory Electric Equipment	6,527,142	2,680,566	41.07%	302,486	4.63%	2,983,051	45.70%
316.00 Miscellaneous Power Plant Equipment	9,921,241	3,075,629	31.00%	304,222	3.07%	3,379,851	34.07%
Total Cholla Common	$82,342,991	$40,718,665	49.45%	$4,314,103	5.24%	$45,032,769	54.69%
Four Corners							
311.00 Structures and Improvements	$48,283,791	$22,009,507	45.58%	$2,899,609	6.01%	$24,909,117	51.59%
312.00 Boiler Plant Equipment	353,157,905	186,622,589	52.84%	24,281,560	6.88%	210,904,149	59.72%
314.00 Turbogenerator Units	68,213,063	34,260,371	50.23%	4,687,018	6.87%	38,947,389	57.10%
315.00 Accessory Electric Equipment	33,335,936	17,325,451	51.97%	2,362,123	7.09%	19,687,574	59.06%
316.00 Miscellaneous Power Plant Equipment	24,153,428	7,512,685	31.10%	1,090,642	4.52%	8,603,327	35.62%
Total Four Corners	$527,144,123	$267,730,603	50.79%	$35,320,953	6.70%	$303,051,556	57.49%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Four Corners Units 1-3							
311.00 Structures and Improvements	$32,557,195	$14,584,446	44.80%	$1,649,618	5.07%	$16,234,064	49.86%
312.00 Boiler Plant Equipment	234,692,935	119,941,748	51.11%	12,758,199	5.44%	132,699,947	56.54%
314.00 Turbogenerator Units	49,894,597	25,151,531	50.41%	2,999,065	6.01%	28,150,596	56.42%
315.00 Accessory Electric Equipment	19,105,566	10,386,352	54.36%	1,166,002	6.10%	11,552,355	60.47%
316.00 Miscellaneous Power Plant Equipment	11,296,591	3,077,552	27.24%	320,481	2.84%	3,398,033	30.08%
Total Four Corners Units 1-3	$347,546,884	$173,141,629	49.82%	$18,893,365	5.44%	$192,034,994	55.25%
Four Corners Units 4-5							
311.00 Structures and Improvements	$11,035,183	$5,714,777	51.79%	$954,368	8.65%	$6,669,145	60.44%
312.00 Boiler Plant Equipment	103,280,404	60,880,415	58.95%	10,532,312	10.20%	71,412,727	69.14%
314.00 Turbogenerator Units	16,330,966	8,116,863	49.70%	1,488,483	9.11%	9,605,346	58.82%
315.00 Accessory Electric Equipment	10,081,177	5,578,838	55.34%	955,265	9.48%	6,534,104	64.81%
316.00 Miscellaneous Power Plant Equipment	3,123,482	1,551,234	49.66%	268,363	8.59%	1,819,597	58.26%
Total Four Corners Units 4-5	$143,851,212	$81,842,127	56.89%	$14,198,791	9.87%	$96,040,918	66.76%
Four Corners Common							
311.00 Structures and Improvements	$4,691,413	$1,710,285	36.46%	$295,624	6.30%	$2,005,908	42.76%
312.00 Boiler Plant Equipment	15,184,566	5,800,427	38.20%	991,049	6.53%	6,791,476	44.73%
314.00 Turbogenerator Units	1,987,500	991,977	49.91%	199,470	10.04%	1,191,447	59.95%
315.00 Accessory Electric Equipment	4,149,193	1,360,260	32.78%	240,856	5.80%	1,601,116	38.59%
316.00 Miscellaneous Power Plant Equipment	9,733,355	2,883,899	29.63%	501,798	5.16%	3,385,697	34.78%
Total Four Corners Common	$35,746,027	$12,746,847	35.66%	$2,228,796	6.24%	$14,975,644	41.89%
Navajo Units 1-3							
311.00 Structures and Improvements	$27,580,268	$14,492,875	52.55%	$1,507,259	5.46%	$16,000,134	58.01%
312.00 Boiler Plant Equipment	161,702,139	79,806,505	49.35%	8,390,718	5.19%	88,197,224	54.54%
314.00 Turbogenerator Units	24,699,305	15,534,678	62.90%	1,693,280	6.86%	17,227,958	69.75%
315.00 Accessory Electric Equipment	20,805,398	12,574,274	60.44%	1,345,447	6.47%	13,919,721	66.90%
316.00 Miscellaneous Power Plant Equipment	16,797,235	7,017,139	41.78%	740,979	4.41%	7,758,118	46.19%
Total Navajo Units 1-3	$251,584,345	$129,425,471	51.44%	$13,677,684	5.44%	$143,103,155	56.88%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Ocotillo Units 1-2							
311.00 Structures and Improvements	$3,796,298	$2,121,832	55.89%	$654,888	17.25%	$2,776,719	73.14%
312.00 Boiler Plant Equipment	24,502,039	15,984,363	65.24%	4,819,414	19.67%	20,803,777	84.91%
314.00 Turbogenerator Units	15,372,486	10,382,067	67.54%	3,134,485	20.39%	13,516,552	87.93%
315.00 Accessory Electric Equipment	2,859,128	1,763,365	61.67%	535,642	18.73%	2,299,007	80.41%
316.00 Miscellaneous Power Plant Equipment	5,544,025	1,956,488	35.29%	630,876	11.38%	2,587,364	46.67%
Total Ocotillo Units 1-2	$52,073,976	$32,208,113	61.85%	$9,775,306	18.77%	$41,983,419	80.62%
Saguaro Units 1-2							
311.00 Structures and Improvements	$3,048,470	$1,996,231	65.48%	$590,335	19.36%	$2,586,566	84.85%
312.00 Boiler Plant Equipment	22,899,016	15,950,784	69.66%	4,746,343	20.73%	20,697,127	90.38%
314.00 Turbogenerator Units	16,513,563	12,364,571	74.88%	3,686,579	22.32%	16,051,150	97.20%
315.00 Accessory Electric Equipment	4,922,271	2,338,010	47.50%	700,521	14.23%	3,038,532	61.73%
316.00 Miscellaneous Power Plant Equipment	3,297,526	1,694,345	51.38%	503,979	15.28%	2,198,324	66.67%
Total Saguaro Units 1-2	$50,680,846	$34,343,940	67.77%	$10,227,758	20.18%	$44,571,699	87.95%
NUCLEAR PRODUCTION (by Unit)							
Palo Verde							
321.00 Structures and Improvements	$657,537,995	$346,957,936	52.77%	$172,669	0.03%	$347,130,605	52.79%
322.00 Reactor Plant Equipment	1,014,755,344	512,819,717	50.54%	(3,062,712)	-0.30%	509,757,005	50.23%
322.10 Steam Generators	25,412,774	14,289,845	56.23%	100,029	0.39%	14,389,874	56.62%
323.00 Turbogenerator Units	346,650,191	180,079,211	51.95%	(102,454)	-0.03%	179,976,757	51.92%
324.00 Accessory Electric Equipment	272,678,334	152,073,334	55.77%	152,983	0.06%	152,226,317	55.83%
325.00 Miscellaneous Power Plant Equipment	137,397,362	66,253,882	48.22%	(662,009)	-0.48%	65,591,874	47.74%
Total Palo Verde	$2,454,432,000	$1,272,473,925	51.84%	($3,401,492)	-0.14%	$1,269,072,432	51.71%
Palo Verde Unit 1							
321.00 Structures and Improvements	$155,161,288	$88,556,500	57.07%	$105,144	0.07%	$88,661,645	57.14%
322.00 Reactor Plant Equipment	436,859,649	214,203,655	49.03%	(616,848)	-0.14%	213,586,807	48.89%
322.10 Steam Generators							
323.00 Turbogenerator Units	121,659,550	62,579,831	51.44%	(64,697)	-0.05%	62,515,134	51.39%
324.00 Accessory Electric Equipment	114,704,738	65,760,339	57.33%	78,611	0.07%	65,838,950	57.40%
325.00 Miscellaneous Power Plant Equipment	30,135,442	16,201,039	53.76%	(57,455)	-0.19%	16,143,583	53.57%
Total Palo Verde Unit 1	$858,520,667	$447,301,364	52.10%	($555,245)	-0.06%	$446,746,119	52.04%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Palo Verde Unit 2							
321.00 Structures and Improvements	$90,571,765	$49,348,785	54.49%	$98,698	0.11%	$49,447,483	54.59%
322.00 Reactor Plant Equipment	226,769,607	107,004,426	47.19%	(1,752,371)	-0.77%	105,252,055	46.41%
322.10 Steam Generators							
323.00 Turbogenerator Units	77,670,724	38,718,669	49.85%	(85,639)	-0.11%	38,633,031	49.74%
324.00 Accessory Electric Equipment	50,017,128	26,974,169	53.93%	29,735	0.06%	27,003,904	53.99%
325.00 Miscellaneous Power Plant Equipment	26,812,162	12,826,698	47.84%	(32,797)	-0.12%	12,793,900	47.72%
Total Palo Verde Unit 2	$471,841,386	$234,872,748	49.78%	($1,742,375)	-0.37%	$233,130,373	49.41%
Palo Verde Unit 3							
321.00 Structures and Improvements	$160,295,268	$89,168,187	55.63%	$178,336	0.11%	$89,346,523	55.74%
322.00 Reactor Plant Equipment	324,634,368	177,647,403	54.72%	(481,494)	-0.15%	177,165,909	54.57%
322.10 Steam Generators	25,412,774	14,289,845	56.23%	100,029	0.39%	14,389,874	56.62%
323.00 Turbogenerator Units	144,937,168	78,319,843	54.04%	70,073	0.05%	78,389,916	54.09%
324.00 Accessory Electric Equipment	89,475,454	49,674,802	55.52%	47,234	0.05%	49,722,036	55.57%
325.00 Miscellaneous Power Plant Equipment	27,650,635	14,443,288	52.23%	(39,166)	-0.14%	14,404,122	52.09%
Total Palo Verde Unit 3	$772,405,667	$423,543,368	54.83%	($124,988)	-0.02%	$423,418,380	54.82%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$140,178,050	$64,499,163	46.01%	($113,672)	-0.08%	$64,385,491	45.93%
322.00 Reactor Plant Equipment	133,326	33,705	25.28%	236	0.18%	33,941	25.46%
322.10 Steam Generators							
323.00 Turbogenerator Units	217,756	99,936	45.89%	(304)	-0.14%	99,633	45.75%
324.00 Accessory Electric Equipment							
325.00 Miscellaneous Power Plant Equipment	88,819	41,092	46.26%	(683)	-0.77%	40,409	45.50%
Total Palo Verde Water Reclamation	$140,617,951	$64,673,896	45.99%	($114,423)	-0.08%	$64,559,473	45.91%
Palo Verde Common							
321.00 Structures and Improvements	$111,331,624	$55,385,300	49.75%	($95,837)	-0.09%	$55,289,463	49.66%
322.00 Reactor Plant Equipment	26,358,394	13,930,527	52.85%	(212,235)	-0.81%	13,718,293	52.05%
322.10 Steam Generators							
323.00 Turbogenerator Units	2,164,993	360,931	16.67%	(21,887)	-1.01%	339,044	15.66%
324.00 Accessory Electric Equipment	18,481,014	9,664,024	52.29%	(2,596)	-0.01%	9,661,427	52.28%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
325.00 Miscellaneous Power Plant Equipment	52,710,304	22,741,766	43.14%	(531,907)	-1.01%	22,209,860	42.14%
Total Palo Verde Common	$211,046,329	$102,082,549	48.37%	($864,462)	-0.41%	$101,218,087	47.96%
OTHER PRODUCTION (by Unit)							
Douglas CT							
341.00 Structures and Improvements	$49,075	$13,250	27.00%	$662	1.35%	$13,912	28.35%
342.00 Fuel Holders, Products and Accessories	137,759	106,959	77.64%	5,796	4.21%	112,755	81.85%
343.00 Prime Movers	1,101,449	1,002,636	91.03%	50,132	4.55%	1,052,768	95.58%
344.00 Generators and Devices	551,765	504,531	91.44%	25,227	4.57%	529,758	96.01%
345.00 Accessory Electric Equipment	353,277	310,641	87.93%	14,893	4.22%	325,534	92.15%
346.00 Miscellaneous Power Plant Equipment	40,913	32,628	79.75%	1,631	3.99%	34,259	83.74%
Total Douglas CT	$2,234,238	$1,970,644	88.20%	$98,341	4.40%	$2,068,986	92.60%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$434,488	$326,770	75.21%	$16,338	3.76%	$343,108	78.97%
342.00 Fuel Holders, Products and Accessories	719,859	549,442	76.33%	27,472	3.82%	576,914	80.14%
343.00 Prime Movers	6,540,275	5,526,360	84.50%	278,712	4.26%	5,805,073	88.76%
344.00 Generators and Devices	6,782,498	4,066,408	59.95%	228,204	3.36%	4,294,612	63.32%
345.00 Accessory Electric Equipment	1,569,515	1,246,378	79.41%	57,739	3.68%	1,304,117	83.09%
346.00 Miscellaneous Power Plant Equipment	558,648	437,265	78.27%	22,342	4.00%	459,606	82.27%
Total Octillo CT Units 1-2	$16,605,283	$12,152,623	73.19%	$630,807	3.80%	$12,783,430	76.98%
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$21,367,258	$3,099,169	14.50%	($1,471,211)	-6.89%	$1,627,958	7.62%
342.00 Fuel Holders, Products and Accessories	1,512,990	26,995	1.78%	1,350	0.09%	28,345	1.87%
343.00 Prime Movers	175,383,772	27,103,603	15.45%	4,989,157	2.84%	32,092,760	18.30%
344.00 Generators and Devices	243,992,340	34,678,000	14.21%	3,596,510	1.47%	38,274,510	15.69%
345.00 Accessory Electric Equipment	22,109,344	3,328,197	15.05%	333,703	1.51%	3,661,900	16.56%
346.00 Miscellaneous Power Plant Equipment	693,357	48,356	6.97%	2,418	0.35%	50,774	7.32%
Total Redhawk CC Units 1-2	$465,059,061	$68,284,321	14.68%	$7,451,927	1.60%	$75,736,248	16.29%
Saguaro							
341.00 Structures and Improvements	$1,414,380	$750,125	53.04%	$37,506	2.65%	$787,631	55.69%
342.00 Fuel Holders, Products and Accessories	1,304,977	1,044,379	80.03%	54,952	4.21%	1,099,331	84.24%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Statement D

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
343.00 Prime Movers	8,624,812	6,867,085	79.62%	343,354	3.98%	7,210,439	83.60%
344.00 Generators and Devices	32,512,372	6,838,010	21.03%	354,850	1.09%	7,192,859	22.12%
345.00 Accessory Electric Equipment	1,698,713	1,358,794	79.99%	65,608	3.86%	1,424,401	83.85%
346.00 Miscellaneous Power Plant Equipment	846,669	512,964	60.59%	26,168	3.09%	539,132	63.68%
Total Saguaro	$46,401,923	$17,371,356	37.44%	$882,437	1.90%	$18,253,793	39.34%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$1,414,380	$750,125	53.04%	$37,506	2.65%	$787,631	55.69%
342.00 Fuel Holders, Products and Accessories	1,304,977	1,044,379	80.03%	54,952	4.21%	1,099,331	84.24%
343.00 Prime Movers	7,983,905	6,761,804	84.69%	338,090	4.23%	7,099,894	88.93%
344.00 Generators and Devices	4,487,988	2,234,502	49.79%	124,674	2.78%	2,359,177	52.57%
345.00 Accessory Electric Equipment	1,576,160	1,338,662	84.93%	64,601	4.10%	1,403,263	89.03%
346.00 Miscellaneous Power Plant Equipment	846,669	512,964	60.59%	26,168	3.09%	539,132	63.68%
Total Saguaro CT Units 1-2	$17,614,079	$12,642,437	71.77%	$645,991	3.67%	$13,288,428	75.44%
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	640,907	105,280	16.43%	5,264	0.82%	110,544	17.25%
344.00 Generators and Devices	28,024,384	4,603,507	16.43%	230,175	0.82%	4,833,683	17.25%
345.00 Accessory Electric Equipment	122,553	20,132	16.43%	1,007	0.82%	21,138	17.25%
346.00 Miscellaneous Power Plant Equipment							
Total Saguaro CT Unit 3	$28,787,844	$4,728,919	16.43%	$236,446	0.82%	$4,965,365	17.25%
Solar Units							
341.00 Structures and Improvements	$418,403	$411,446	98.34%	$20,691	4.95%	$432,136	103.28%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices	15,334,956	10,639,078	69.38%	505,613	3.30%	11,144,691	72.68%
345.00 Accessory Electric Equipment	166,635	120,382	72.24%	6,019	3.61%	126,402	75.86%
346.00 Miscellaneous Power Plant Equipment							
Total Solar Units	$15,919,994	$11,170,906	70.17%	$532,322	3.34%	$11,703,229	73.51%

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Statement D

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Sundance							
341.00 Structures and Improvements	$12,482,674	$4,649,708	37.25%	$232,485	1.86%	$4,882,194	39.11%
342.00 Fuel Holders, Products and Accessories	4,254,044	1,603,793	37.70%	80,190	1.89%	1,683,983	39.59%
343.00 Prime Movers	229,648,056	86,233,205	37.55%	4,311,660	1.88%	90,544,865	39.43%
344.00 Generators and Devices	297,855	42,715	14.34%	2,136	0.72%	44,851	15.06%
345.00 Accessory Electric Equipment	25,914,410	9,769,846	37.70%	488,492	1.89%	10,258,339	39.59%
346.00 Miscellaneous Power Plant Equipment	1,220,859	460,269	37.70%	23,013	1.89%	483,283	39.59%
Total Sun Dance	$273,817,898	$102,759,537	37.53%	$5,137,977	1.88%	$107,897,514	39.40%
West Phoenix							
341.00 Structures and Improvements	$23,501,929	$5,836,221	24.83%	$246,650	1.05%	$6,082,871	25.88%
342.00 Fuel Holders, Products and Accessories	26,801,921	7,251,939	27.06%	362,597	1.35%	7,614,536	28.41%
343.00 Prime Movers	164,814,870	27,075,233	16.43%	2,913,679	1.77%	29,988,912	18.20%
344.00 Generators and Devices	231,622,565	41,070,288	17.73%	2,613,983	1.13%	43,684,271	18.86%
345.00 Accessory Electric Equipment	29,999,485	6,753,238	22.51%	360,607	1.20%	7,113,845	23.71%
346.00 Miscellaneous Power Plant Equipment	3,871,189	1,732,912	44.76%	79,720	2.06%	1,812,631	46.82%
Total West Phoenix	$480,611,959	$89,719,829	18.67%	$6,577,236	1.37%	$96,297,065	20.04%
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$3,307,106	$660,702	19.98%	$35,790	1.08%	$696,491	21.06%
342.00 Fuel Holders, Products and Accessories	21,229,279	5,339,673	25.15%	266,984	1.26%	5,606,657	26.41%
343.00 Prime Movers							
344.00 Generators and Devices	91,829,248	21,570,995	23.49%	1,664,635	1.81%	23,235,630	25.30%
345.00 Accessory Electric Equipment	16,524,179	4,087,410	24.74%	230,325	1.39%	4,317,734	26.13%
346.00 Miscellaneous Power Plant Equipment	2,760,231	1,119,025	40.54%	49,025	1.78%	1,168,051	42.32%
Total West Phoenix CC Units 1-3	$135,650,043	$32,777,804	24.16%	$2,246,758	1.66%	$35,024,563	25.82%

Statement D

ARIZONA PUBLIC SERVICE COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$4,524,163	$746,124	16.49%	$37,306	0.82%	$783,430	17.32%
342.00 Fuel Holders, Products and Accessories	4,135,109	752,731	18.20%	37,637	0.91%	790,367	19.11%
343.00 Prime Movers	54,739,557	9,964,467	18.20%	498,223	0.91%	10,462,691	19.11%
344.00 Generators and Devices	15,261,009	2,583,146	16.93%	103,540	0.68%	2,686,686	17.60%
345.00 Accessory Electric Equipment	59,871	6,439	10.75%	322	0.54%	6,761	11.29%
346.00 Miscellaneous Power Plant Equipment	27,151	3,328	12.26%	166	0.61%	3,494	12.87%
Total West Phoenix CC Unit 4	$78,746,860	$14,056,234	17.85%	$677,195	0.86%	$14,733,429	18.71%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$10,804,474	$1,223,350	11.32%	$61,168	0.57%	$1,284,518	11.89%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	101,281,146	10,418,941	10.29%	2,072,868	2.05%	12,491,809	12.33%
344.00 Generators and Devices	119,641,646	13,518,126	11.30%	675,906	0.56%	14,194,032	11.86%
345.00 Accessory Electric Equipment	11,706,160	1,333,785	11.39%	66,689	0.57%	1,400,475	11.96%
346.00 Miscellaneous Power Plant Equipment	24,203	1,600	6.61%	80	0.33%	1,680	6.94%
Total West Phoenix CC Unit 5	$243,457,629	$26,495,803	10.88%	$2,876,711	1.18%	$29,372,514	12.06%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$510,951	$425,525	83.28%	$21,276	4.16%	$446,801	87.45%
342.00 Fuel Holders, Products and Accessories	1,437,533	1,159,535	80.66%	57,977	4.03%	1,217,512	84.69%
343.00 Prime Movers	8,794,167	6,691,824	76.09%	342,588	3.90%	7,034,412	79.99%
344.00 Generators and Devices	4,890,662	3,398,021	69.48%	169,901	3.47%	3,567,922	72.95%
345.00 Accessory Electric Equipment	1,709,275	1,325,604	77.55%	63,272	3.70%	1,388,875	81.26%
346.00 Miscellaneous Power Plant Equipment	1,059,604	608,958	57.47%	30,448	2.87%	639,406	60.34%
Total West Phoenix CT Units 1-2	$18,402,192	$13,609,467	73.96%	$685,461	3.72%	$14,294,928	77.68%

ARIZONA PUBLIC SERVICE COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2007

Account Description	Plant Investment	Investment Reserve		Net Salvage Reserve		Total Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
West Phoenix Common							
341.00 Structures and Improvements	$4,355,235	$2,780,520	63.84%	$91,110	2.09%	$2,871,631	65.94%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers							
344.00 Generators and Devices							
345.00 Accessory Electric Equipment							
346.00 Miscellaneous Power Plant Equipment							
Total West Phoenix Common	$4,355,235	$2,780,520	63.84%	$91,110	2.09%	$2,871,631	65.94%
Yucca CT Units 1-4							
341.00 Structures and Improvements	$537,719	$301,211	56.02%	$15,445	2.87%	$316,656	58.89%
342.00 Fuel Holders, Products and Accessories	3,244,987	2,920,953	90.01%	147,264	4.54%	3,068,216	94.55%
343.00 Prime Movers	7,962,254	7,393,401	92.86%	369,670	4.64%	7,763,071	97.50%
344.00 Generators and Devices	6,526,095	4,433,386	67.93%	225,556	3.46%	4,658,942	71.39%
345.00 Accessory Electric Equipment	2,712,683	1,925,484	70.98%	93,208	3.44%	2,018,692	74.42%
346.00 Miscellaneous Power Plant Equipment	561,193	397,881	70.90%	19,894	3.54%	417,776	74.44%
Total Yucca CT Units 1-4	$21,544,931	$17,372,316	80.63%	$871,037	4.04%	$18,243,354	84.68%

Statement E

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION									
311.00 Structures and Improvements	$141,417,078	$1,682,438	$139,734,640	-3.2%	-12.5%	($53,838)	($17,475,161)	($17,528,999)	-12.4%
312.00 Boiler Plant Equipment	969,537,030	56,991,878	912,545,152	-19.4%	-12.9%	(11,056,424)	(118,003,215)	(129,059,639)	-13.3%
314.00 Turbogenerator Units	255,905,048	29,490,508	226,414,540	-3.9%	-14.5%	(1,150,130)	(32,870,482)	(34,020,611)	-13.3%
315.00 Accessory Electric Equipment	156,185,617	4,575,532	151,610,085	-12.5%	-12.5%	(571,942)	(18,900,446)	(19,472,387)	-12.5%
316.00 Miscellaneous Power Plant Equipment	76,462,609	3,911,475	72,551,134	-17.1%	-14.6%	(668,862)	(10,593,225)	(11,262,087)	-14.7%
Total Steam Production Plant	$1,599,507,382	$96,651,831	$1,502,855,551	-14.0%	-13.2%	($13,501,196)	($197,842,528)	($211,343,724)	-13.2%
NUCLEAR PRODUCTION									
321.00 Structures and Improvements	$677,283,345	$19,745,350	$657,537,995	-5.0%	-0.2%	($987,268)	($1,315,076)	($2,302,343)	-0.3%
322.00 Reactor Plant Equipment	1,066,394,863	51,639,519	1,014,755,344	-24.0%	-0.7%	(12,393,485)	(6,666,428)	(19,059,912)	-1.8%
322.10 Steam Generators	25,412,774		25,412,774		-0.7%		(177,889)	(177,889)	-0.7%
323.00 Turbogenerator Units	378,564,836	31,914,645	346,650,191	-3.3%	-0.2%	(1,053,183)	(693,300)	(1,746,484)	-0.5%
324.00 Accessory Electric Equipment	277,041,418	4,363,084	272,678,334	-4.9%	-0.2%	(213,791)	(545,357)	(759,148)	-0.3%
325.00 Miscellaneous Power Plant Equipment	175,406,205	38,008,843	137,397,362	-4.8%	-0.2%	(1,824,424)	(274,795)	(2,099,219)	-1.2%
Total Nuclear Production Plant	$2,600,103,441	$145,671,441	$2,454,432,000	-11.3%	-0.4%	($16,472,151)	($9,672,845)	($26,144,996)	-1.0%
OTHER PRODUCTION									
341.00 Structures and Improvements	$64,462,783	$4,256,857	$60,205,926	-54.5%	-5.0%	($2,321,621)	($3,010,296)	($5,331,917)	-8.3%
342.00 Fuel Holders, Products and Accessories	39,553,323	1,576,786	37,976,537	-4.8%	-5.0%	(76,416)	(1,898,827)	(1,975,243)	-5.0%
343.00 Prime Movers	658,599,083	64,523,595	594,075,488	5.9%	-5.0%	3,829,177	(29,703,774)	(25,874,597)	-3.9%
344.00 Generators and Devices	619,381,540	81,761,094	537,620,446	-1.0%	-5.0%	(815,127)	(26,881,022)	(27,696,150)	-4.5%
345.00 Accessory Electric Equipment	89,929,850	5,405,788	84,524,062	-0.8%	-5.0%	(45,480)	(4,226,203)	(4,271,683)	-4.8%
346.00 Miscellaneous Power Plant Equipment	8,285,492	492,664	7,792,828	-7.1%	-5.0%	(35,114)	(389,641)	(424,756)	-5.1%
Total Other Production Plant	$1,480,212,071	$158,016,784	$1,322,195,287	0.3%	-5.0%	$535,419	($66,109,764)	($65,574,345)	-4.4%
TRANSMISSION PLANT									
352.02 Structures and Improvements	$95,935		$95,935						
353.00 Station Equipment	79,971,446	2,258,917	77,712,529						
354.00 Towers and Fixtures	1,329,316		1,329,316						
355.00 Poles and Fixtures	1,366,890		1,366,890		-20.0%		(273,378)	(273,378)	-20.0%
356.00 Overhead Conductors and Devices	2,086,319	138,642	1,947,677		20.0%		389,535	389,535	18.7%
Total Transmission Plant	$84,849,906	$2,397,559	$82,452,347		0.1%		$116,157	$116,157	0.1%
DISTRIBUTION PLANT									
361.00 Structures and Improvements	$39,297,034	$1,010,751	$38,286,283	8.8%	-5.0%	$88,946	($1,914,314)	($1,825,368)	-4.6%
362.00 Station Equipment	369,343,948	44,721,185	324,622,763	10.4%	10.0%	4,651,003	32,462,276	37,113,280	10.0%
364.01 Poles, Towers and Fixtures - Wood	400,872,434	94,762,797	306,109,637	14.2%	-5.0%	13,456,317	(15,305,482)	(1,849,165)	-0.5%
364.02 Poles, Towers and Fixtures - Steel	133,510,786	3,050,896	130,459,890	-34.7%	-5.0%	(1,058,661)	(6,522,995)	(7,581,655)	-5.7%
365.00 Overhead Conductors and Devices	333,193,333	60,611,578	272,581,755	11.0%	10.0%	6,667,274	27,258,176	33,925,449	10.2%
366.00 Underground Conduit	598,925,468	21,168,540	577,756,928	-4.9%	-5.0%	(1,037,258)	(28,887,846)	(29,925,105)	-5.0%
367.00 Underground Conductors and Devices	1,414,006,120	179,182,548	1,234,823,572	1.4%	-5.0%	2,508,556	(61,741,179)	(59,232,623)	-4.2%
368.00 Line Transformers	706,183,291	52,671,152	653,512,139	3.8%	-5.0%	2,001,504	(32,675,607)	(30,674,103)	-4.3%
369.00 Services	351,618,349	42,200,702	309,417,647	0.2%		84,401		84,401	

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
370.01 Meters - Electronic	105,109,560	11,140,753	93,968,807						
370.02 Meters - Electromechanical	146,670,513	74,510,135	72,160,378						
370.03 Meters - AMI	14,033,538		14,033,538						
371.00 Installations on Customers' Premises	44,470,872	5,424,195	39,046,677	-14.7%	-10.0%	(797,357)	(3,904,668)	(4,702,024)	-10.6%
373.00 Street Lighting and Signal Systems	80,646,596	10,209,262	70,437,334	-2.5%	-10.0%	(255,232)	(7,043,733)	(7,298,965)	-9.1%
Total Distribution Plant	$4,737,881,842	$600,664,494	$4,137,217,348	4.4%	-2.4%	$26,309,493	($98,275,372)	($71,965,878)	-1.5%
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$130,211,607	$18,554,182	$111,657,425	-6.9%	-5.0%	($1,280,239)	($5,582,871)	($6,863,110)	-5.3%
391.CM Office Furn. and Equip. - Computer	205,450,985	136,291,067	69,159,918	-0.1%		(136,291)		(136,291)	-0.1%
392.EL Transportation Equipment - Electric Vehicles	1,757,880	59,776	1,698,104	-2.6%		(1,554)		(1,554)	-0.1%
392.HD Transportation Equipment - Heavy Duty	3,879,098	252,889	3,626,209	-46.2%		(116,835)		(116,835)	-3.0%
392.LD Transportation Equipment - Light Duty	22,164,297	7,878,319	14,285,978	19.2%	15.0%	1,512,637	2,142,897	3,655,534	16.5%
392.MD Transportation Equipment - Medium Duty	2,387,799	994,863	1,392,936						
392.TR Transportation Equipment - Trailers	4,733,574	304,685	4,428,889						
396.00 Power Operated Equipment	49,615,884	38,908,657	10,707,227	3.0%	3.0%	1,167,260	321,217	1,488,477	3.0%
397.00 Communication Equipment	177,999,352	57,000,882	120,998,470	0.1%		57,001		57,001	
Total Depreciable	$598,200,476	$260,245,320	$337,955,156	0.5%	-0.9%	$1,201,979	($3,118,758)	($1,916,778)	-0.3%
Amortizable									
391.FE Office Furn. and Equip. - Furniture	$64,374,753	$13,184,258	$51,190,495						
393.00 Stores Equipment	1,385,863	148,298	1,237,565						
394.00 Tools, Shop and Garage Equipment	31,631,642	11,092,264	20,539,378						
395.00 Laboratory Equipment	2,294,520	399,982	1,894,538						
398.00 Miscellaneous Equipment	11,724,513	1,214,114	10,510,399						
Total Amortizable	$111,411,291	$26,038,916	$85,372,375						
Total General Plant	$709,611,767	$286,284,236	$423,327,531	0.4%	-0.7%	$1,201,979	($3,118,758)	($1,916,778)	-0.3%
TOTAL UTILITY	$11,212,166,409	$1,289,686,345	$9,922,480,064	-0.1%	-3.8%	($1,926,455)	($374,903,109)	($376,829,564)	-3.4%
STEAM PRODUCTION (by Unit)									
Cholla									
311.00 Structures and Improvements	$57,843,402	$817,589	$57,025,813	-3.2%	-11.1%	($26,163)	($6,312,615)	($6,338,778)	-11.0%
312.00 Boiler Plant Equipment	368,254,700	17,970,647	350,284,053		-11.1%	(3,486,306)	(38,997,924)	(42,484,229)	-11.5%
314.00 Turbogenerator Units	123,986,353	22,370,230	101,616,123		-11.6%	(872,439)	(11,822,559)	(12,694,998)	-10.2%
315.00 Accessory Electric Equipment	91,958,140	2,270,788	89,687,352		-10.9%	(283,849)	(9,794,149)	(10,077,998)	-11.0%
316.00 Miscellaneous Power Plant Equipment	24,637,612	1,878,692	22,758,920		-11.4%	(321,256)	(2,599,027)	(2,920,284)	-11.9%
Total Cholla	$666,680,207	$45,307,946	$621,372,261	-11.0%	-11.2%	($4,990,012)	($69,526,275)	($74,516,287)	-11.2%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Cholla Unit 1									
311.00 Structures and Improvements	$3,830,260	$181,357	$3,648,903	-3.2%	-9.4%	($5,803)	($342,997)	($348,800)	-9.1%
312.00 Boiler Plant Equipment	70,704,438	2,510,972	68,193,466	-19.4%	-9.9%	(487,129)	(6,751,153)	(7,238,282)	-10.2%
314.00 Turbogenerator Units	11,581,709	470,625	11,111,084	-3.9%	-9.9%	(18,354)	(1,099,997)	(1,118,352)	-9.7%
315.00 Accessory Electric Equipment	7,560,896	51,985	7,508,911	-12.5%	-9.6%	(6,498)	(720,855)	(727,354)	-9.6%
316.00 Miscellaneous Power Plant Equipment	2,441,577	9,353	2,432,224	-17.1%	-9.9%	(1,599)	(240,790)	(242,390)	-9.9%
Total Cholla Unit 1	$96,118,880	$3,224,292	$92,894,588	-16.1%	-9.9%	($519,384)	($9,155,793)	($9,675,177)	-10.1%
Cholla Unit 2									
311.00 Structures and Improvements	$5,498,815	$46,274	$5,452,541	-3.2%	-9.4%	($1,481)	($512,539)	($514,020)	-9.3%
312.00 Boiler Plant Equipment	154,107,433	5,304,864	148,802,569	-19.4%	-10.1%	(1,029,144)	(15,029,059)	(16,058,203)	-10.4%
314.00 Turbogenerator Units	44,627,332	6,772,570	37,854,762	-3.9%	-10.0%	(264,130)	(3,785,476)	(4,049,606)	-9.1%
315.00 Accessory Electric Equipment	45,576,997	691,217	44,885,780	-12.5%	-9.7%	(86,402)	(4,353,921)	(4,440,323)	-9.7%
316.00 Miscellaneous Power Plant Equipment	6,096,347	284,183	5,812,164	-17.1%	-10.0%	(48,595)	(581,216)	(629,812)	-10.3%
Total Cholla Unit 2	$255,906,924	$13,099,108	$242,807,816	-10.9%	-10.0%	($1,429,752)	($24,262,212)	($25,691,964)	-10.0%
Cholla Unit 3									
311.00 Structures and Improvements	$9,850,470	$30,850	$9,819,620	-3.2%	-12.5%	($987)	($1,227,453)	($1,228,440)	-12.5%
312.00 Boiler Plant Equipment	110,513,992	4,105,061	106,408,931	-19.4%	-13.2%	(796,382)	(14,045,979)	(14,842,361)	-13.4%
314.00 Turbogenerator Units	66,056,144	14,316,639	51,739,505	-3.9%	-13.2%	(558,349)	(6,829,615)	(7,387,964)	-11.2%
315.00 Accessory Electric Equipment	31,290,757	525,238	30,765,519	-12.5%	-12.9%	(65,655)	(3,968,752)	(4,034,407)	-12.9%
316.00 Miscellaneous Power Plant Equipment	4,815,515	222,224	4,593,291	-17.1%	-13.2%	(38,000)	(606,314)	(644,315)	-13.4%
Total Cholla Unit 3	$222,526,878	$19,200,012	$203,326,866	-7.6%	-13.1%	($1,459,373)	($26,678,112)	($28,137,485)	-12.6%
Cholla Common									
311.00 Structures and Improvements	$38,663,857	$559,108	$38,104,749	-3.2%	-11.1%	($17,891)	($4,229,627)	($4,247,519)	-11.0%
312.00 Boiler Plant Equipment	32,928,837	6,049,750	26,879,087	-19.4%	-11.8%	(1,173,652)	(3,171,732)	(4,345,384)	-13.2%
314.00 Turbogenerator Units	1,721,168	810,396	910,772	-3.9%	-11.8%	(31,605)	(107,471)	(139,077)	-8.1%
315.00 Accessory Electric Equipment	7,529,490	1,002,348	6,527,142	-12.5%	-11.5%	(125,294)	(750,621)	(875,915)	-11.6%
316.00 Miscellaneous Power Plant Equipment	11,284,173	1,362,932	9,921,241	-17.1%	-11.8%	(233,061)	(1,170,706)	(1,403,768)	-12.4%
Total Cholla Common	$92,127,525	$9,784,534	$82,342,991	-16.2%	-11.5%	($1,581,503)	($9,430,158)	($11,011,662)	-12.0%
Four Corners									
311.00 Structures and Improvements	$48,750,310	$466,519	$48,283,791	-3.2%	-13.0%	($14,929)	($6,272,747)	($6,287,676)	-12.9%
312.00 Boiler Plant Equipment	384,381,237	31,223,332	353,157,905		-13.4%	(5,057,326)	(47,249,434)	(53,306,761)	-13.9%
314.00 Turbogenerator Units	74,729,211	6,516,148	68,213,063		-13.0%	(254,130)	(8,857,079)	(9,111,208)	-12.2%
315.00 Accessory Electric Equipment	35,269,820	1,933,884	33,335,936		-13.7%	(241,736)	(4,578,092)	(4,819,827)	-13.7%
316.00 Miscellaneous Power Plant Equipment	25,057,188	903,760	24,153,428		-14.6%	(154,543)	(3,521,778)	(3,676,320)	-14.7%
Total Four Corners	$568,187,766	$41,043,643	$527,144,123	-16.4%	-13.4%	($6,722,663)	($70,479,130)	($77,201,793)	-13.6%
Four Corners Units 1-3									
311.00 Structures and Improvements	$32,820,708	$263,513	$32,557,195	-3.2%	-11.2%	($8,432)	($3,646,406)	($3,654,838)	-11.1%
312.00 Boiler Plant Equipment	263,413,308	28,720,373	234,692,935	-19.4%	-11.4%	(5,571,752)	(26,754,995)	(32,326,747)	-12.3%
314.00 Turbogenerator Units	54,430,781	4,536,184	49,894,597	-3.9%	-11.4%	(176,911)	(5,687,984)	(5,864,895)	-10.8%
315.00 Accessory Electric Equipment	20,229,005	1,123,439	19,105,566	-12.5%	-11.3%	(140,430)	(2,158,929)	(2,299,359)	-11.4%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
316.00 Miscellaneous Power Plant Equipment	12,060,218	763,627	11,296,591	-17.1%	-11.4%	(130,580)	(1,287,811)	(1,418,392)	-11.8%
Total Four Corners Units 1-3	$382,954,020	$35,407,136	$347,546,884	-17.0%	-11.4%	($6,028,106)	($39,536,125)	($45,564,231)	-11.9%
Four Corners Units 4-5									
311.00 Structures and Improvements	$11,056,297	$21,114	$11,035,183	-3.2%	-16.7%	($676)	($1,842,876)	($1,843,551)	-16.7%
312.00 Boiler Plant Equipment	104,583,760	1,303,356	103,280,404	-19.4%	-17.3%	(252,851)	(17,867,510)	(18,120,361)	-17.3%
314.00 Turbogenerator Units	17,185,681	854,715	16,330,966	-3.9%	-17.3%	(33,334)	(2,825,257)	(2,858,591)	-16.6%
315.00 Accessory Electric Equipment	10,413,174	331,997	10,081,177	-12.5%	-17.0%	(41,500)	(1,713,800)	(1,755,300)	-16.9%
316.00 Miscellaneous Power Plant Equipment	3,156,521	33,039	3,123,482	-17.1%	-17.3%	(5,650)	(540,362)	(546,012)	-17.3%
Total Four Corners Units 4-5	$146,395,433	$2,544,221	$143,851,212	-13.1%	-17.2%	($334,010)	($24,789,805)	($25,123,815)	-17.2%
Four Corners Common									
311.00 Structures and Improvements	$4,873,305	$181,892	$4,691,413	-3.2%	-16.7%	($5,821)	($783,466)	($789,287)	-16.2%
312.00 Boiler Plant Equipment	16,384,169	1,199,603	15,184,566	-19.4%	-17.3%	(232,723)	(2,626,930)	(2,859,653)	-17.5%
314.00 Turbogenerator Units	3,112,749	1,125,249	1,987,500	-3.9%	-17.3%	(43,885)	(343,838)	(387,722)	-12.5%
315.00 Accessory Electric Equipment	4,627,641	478,448	4,149,193	-12.5%	-17.0%	(59,806)	(705,363)	(765,169)	-16.5%
316.00 Miscellaneous Power Plant Equipment	9,840,449	107,094	9,733,355	-17.1%	-17.4%	(18,313)	(1,693,604)	(1,711,917)	-17.4%
Total Four Corners Common	$38,838,313	$3,092,286	$35,746,027	-11.7%	-17.2%	($360,547)	($6,153,200)	($6,513,747)	-16.8%
Navajo Units 1-3									
311.00 Structures and Improvements	$27,709,725	$129,457	$27,580,268	-3.2%	-10.4%	($4,143)	($2,868,348)	($2,872,490)	-10.4%
312.00 Boiler Plant Equipment	168,297,760	6,595,621	161,702,139	-19.4%	-10.9%	(1,279,550)	(17,625,533)	(18,905,084)	-11.2%
314.00 Turbogenerator Units	24,801,608	102,303	24,699,305	-3.9%	-10.9%	(3,990)	(2,692,224)	(2,696,214)	-10.9%
315.00 Accessory Electric Equipment	20,915,482	110,084	20,805,398	-12.5%	-10.7%	(13,761)	(2,226,178)	(2,239,938)	-10.7%
316.00 Miscellaneous Power Plant Equipment	17,330,256	533,021	16,797,235	-17.1%	-10.9%	(91,147)	(1,830,899)	(1,922,045)	-11.1%
Total Navajo Units 1-3	$259,054,831	$7,470,486	$251,584,345	-18.6%	-10.8%	($1,392,590)	($27,243,181)	($28,635,771)	-11.1%
Ocotillo Units 1-2									
311.00 Structures and Improvements	$4,001,553	$205,255	$3,796,298	-3.2%	-29.8%	($6,568)	($1,131,297)	($1,137,865)	-28.4%
312.00 Boiler Plant Equipment	24,788,387	286,348	24,502,039	-19.4%	-30.1%	(55,552)	(7,375,114)	(7,430,665)	-30.0%
314.00 Turbogenerator Units	15,496,075	123,589	15,372,486	-3.9%	-30.1%	(4,820)	(4,627,118)	(4,631,938)	-29.9%
315.00 Accessory Electric Equipment	2,993,446	134,318	2,859,128	-12.5%	-29.9%	(16,790)	(854,879)	(871,669)	-29.1%
316.00 Miscellaneous Power Plant Equipment	6,097,163	553,138	5,544,025	-17.1%	-30.1%	(94,587)	(1,668,752)	(1,763,338)	-28.9%
Total Ocotillo Units 1-2	$53,376,624	$1,302,648	$52,073,976	-13.7%	-30.1%	($178,316)	($15,657,160)	($15,835,476)	-29.7%
Saguaro Units 1-2									
311.00 Structures and Improvements	$3,112,088	$63,618	$3,048,470	-3.2%	-29.2%	($2,036)	($890,153)	($892,189)	-28.7%
312.00 Boiler Plant Equipment	23,814,946	915,930	22,899,016	-19.4%	-29.5%	(177,690)	(6,755,210)	(6,932,900)	-29.1%
314.00 Turbogenerator Units	16,891,801	378,238	16,513,563	-3.9%	-29.5%	(14,751)	(4,871,501)	(4,886,252)	-28.9%
315.00 Accessory Electric Equipment	5,048,729	126,458	4,922,271	-12.5%	-29.4%	(15,807)	(1,447,148)	(1,462,955)	-29.0%
316.00 Miscellaneous Power Plant Equipment	3,340,390	42,864	3,297,526	-17.1%	-29.5%	(7,330)	(972,770)	(980,100)	-29.3%
Total Saguaro Units 1-2	$52,207,954	$1,527,108	$50,680,846	-14.3%	-29.5%	($217,614)	($14,936,782)	($15,154,396)	-29.0%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
NUCLEAR PRODUCTION (by Unit)									
Palo Verde									
321.00 Structures and Improvements	$677,283,345	$19,745,350	$657,537,995	-5.0%	-0.2%	($987,268)	($1,315,076)	($2,302,343)	-0.3%
322.00 Reactor Plant Equipment	1,066,394,863	51,639,519	1,014,755,344		-0.7%	(12,393,485)	(6,666,428)	(19,059,912)	-1.8%
322.10 Steam Generators	25,412,774		25,412,774		-0.7%		(177,889)	(177,889)	-0.7%
323.00 Turbogenerator Units	378,564,836	31,914,645	346,650,191		-0.2%	(1,053,183)	(693,300)	(1,746,484)	-0.5%
324.00 Accessory Electric Equipment	277,041,418	4,363,084	272,678,334		-0.2%	(213,791)	(545,357)	(759,148)	-0.3%
325.00 Miscellaneous Power Plant Equipment	175,406,205	38,008,843	137,397,362		-0.2%	(1,824,424)	(274,795)	(2,099,219)	-1.2%
Total Palo Verde	$2,600,103,441	$145,671,441	$2,454,432,000	-11.3%	-0.4%	($16,472,151)	($9,672,845)	($26,144,996)	-1.0%
Palo Verde Unit 1									
321.00 Structures and Improvements	$156,895,424	$1,734,136	$155,161,288	-5.0%	-0.2%	($86,707)	($310,323)	($397,029)	-0.3%
322.00 Reactor Plant Equipment	451,974,754	15,115,105	436,859,649	-24.0%	-0.6%	(3,627,625)	(2,621,158)	(6,248,783)	-1.4%
322.10 Steam Generators									
323.00 Turbogenerator Units	135,945,796	14,286,246	121,659,550	-3.3%	-0.2%	(471,446)	(243,319)	(714,765)	-0.5%
324.00 Accessory Electric Equipment	115,996,098	1,291,360	114,704,738	-4.9%	-0.2%	(63,277)	(229,409)	(292,686)	-0.3%
325.00 Miscellaneous Power Plant Equipment	34,423,461	4,288,019	30,135,442	-4.8%	-0.2%	(205,825)	(60,271)	(266,096)	-0.8%
Total Palo Verde Unit 1	$895,235,533	$36,714,866	$858,520,667	-12.1%	-0.4%	($4,454,880)	($3,464,480)	($7,919,360)	-0.9%
Palo Verde Unit 2									
321.00 Structures and Improvements	$91,260,731	$688,966	$90,571,765	-5.0%	-0.2%	($34,448)	($181,144)	($215,592)	-0.2%
322.00 Reactor Plant Equipment	248,115,359	21,345,752	226,769,607	-24.0%	-0.7%	(5,122,980)	(1,587,387)	(6,710,368)	-2.7%
322.10 Steam Generators									
323.00 Turbogenerator Units	88,391,943	10,721,219	77,670,724	-3.3%	-0.2%	(353,800)	(155,341)	(509,142)	-0.6%
324.00 Accessory Electric Equipment	51,112,022	1,094,894	50,017,128	-4.9%	-0.2%	(53,650)	(100,034)	(153,684)	-0.3%
325.00 Miscellaneous Power Plant Equipment	29,104,205	2,292,043	26,812,162	-4.8%	-0.2%	(110,018)	(53,624)	(163,642)	-0.6%
Total Palo Verde Unit 2	$507,984,260	$36,142,874	$471,841,386	-15.7%	-0.4%	($5,674,897)	($2,077,531)	($7,752,428)	-1.5%
Palo Verde Unit 3									
321.00 Structures and Improvements	$161,685,112	$1,389,844	$160,295,268	-5.0%	-0.2%	($69,492)	($320,591)	($390,083)	-0.2%
322.00 Reactor Plant Equipment	337,358,825	12,724,457	324,634,368	-24.0%	-0.7%	(3,053,870)	(2,272,441)	(5,326,310)	-1.6%
322.10 Steam Generators	25,412,774		25,412,774		-0.7%		(177,889)	(177,889)	-0.7%
323.00 Turbogenerator Units	150,676,712	5,739,544	144,937,168	-3.3%	-0.2%	(189,405)	(289,874)	(479,279)	-0.3%
324.00 Accessory Electric Equipment	90,579,242	1,103,788	89,475,454	-4.9%	-0.2%	(54,086)	(178,951)	(233,037)	-0.3%
325.00 Miscellaneous Power Plant Equipment	30,470,759	2,820,124	27,650,635	-4.8%	-0.2%	(135,366)	(55,301)	(190,667)	-0.6%
Total Palo Verde Unit 3	$796,183,424	$23,777,757	$772,405,667	-14.7%	-0.4%	($3,502,218)	($3,295,047)	($6,797,265)	-0.9%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$148,944,077	$8,766,027	$140,178,050	-5.0%	-0.2%	($438,301)	($280,356)	($718,657)	-0.5%
322.00 Reactor Plant Equipment	133,326		133,326	-24.0%	-0.7%		(933)	(933)	-0.7%
322.10 Steam Generators									
323.00 Turbogenerator Units	246,532	28,776	217,756	-3.3%	-0.2%	(950)	(436)	(1,385)	-0.6%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
324.00 Accessory Electric Equipment									
325.00 Miscellaneous Power Plant Equipment	131,432	42,613	88,819	-4.8%	-0.2%	(2,045)	(178)	(2,223)	-1.7%
Total Palo Verde Water Reclamation	$149,455,367	$8,837,416	$140,617,951	-5.0%	-0.2%	($441,296)	($281,903)	($723,199)	-0.5%
Palo Verde Common									
321.00 Structures and Improvements	$118,498,001	$7,166,377	$111,331,624	-5.0%	-0.2%	($358,319)	($222,663)	($580,982)	-0.5%
322.00 Reactor Plant Equipment	28,812,599	2,454,205	26,358,394	-24.0%	-0.7%	(589,009)	(184,509)	(773,518)	-2.7%
322.10 Steam Generators									
323.00 Turbogenerator Units	3,303,853	1,138,860	2,164,993	-3.3%	-0.2%	(37,582)	(4,330)	(41,912)	-1.3%
324.00 Accessory Electric Equipment	19,354,056	873,042	18,481,014	-4.9%	-0.2%	(42,779)	(36,962)	(79,741)	-0.4%
325.00 Miscellaneous Power Plant Equipment	81,276,348	28,566,044	52,710,304	-4.8%	-0.2%	(1,371,170)	(105,421)	(1,476,591)	-1.8%
Total Palo Verde Common	$251,244,857	$40,198,528	$211,046,329	-6.0%	-0.3%	($2,398,860)	($553,885)	($2,952,744)	-1.2%
OTHER PRODUCTION (by Unit)									
Douglas CT									
341.00 Structures and Improvements	$49,075		$49,075		-5.0%		($2,454)	($2,454)	-5.0%
342.00 Fuel Holders, Products and Accessories	160,633	22,874	137,759		-5.0%		(6,888)	(6,888)	-4.3%
343.00 Prime Movers	1,101,449		1,101,449		-5.0%		(55,072)	(55,072)	-5.0%
344.00 Generators and Devices	551,765		551,765		-5.0%		(27,588)	(27,588)	-5.0%
345.00 Accessory Electric Equipment	369,401	16,124	353,277	-17.1%	-5.0%	(2,757)	(17,664)	(20,421)	-5.5%
346.00 Miscellaneous Power Plant Equipment	40,913		40,913		-5.0%		(2,046)	(2,046)	-5.0%
Total Douglas CT	$2,273,236	$38,998	$2,234,238	-7.1%	-5.0%	($2,757)	($111,712)	($114,469)	-5.0%
Ocotillo CT Units 1-2									
341.00 Structures and Improvements	$434,488		$434,488		-5.0%		($21,724)	($21,724)	-5.0%
342.00 Fuel Holders, Products and Accessories	719,859		719,859		-5.0%		(35,993)	(35,993)	-5.0%
343.00 Prime Movers	6,636,736	96,461	6,540,275		-5.0%		(327,014)	(327,014)	-4.9%
344.00 Generators and Devices	7,672,332	889,834	6,782,498		-5.0%		(339,125)	(339,125)	-4.4%
345.00 Accessory Electric Equipment	1,663,440	93,925	1,569,515	-17.1%	-5.0%	(16,061)	(78,476)	(94,537)	-5.7%
346.00 Miscellaneous Power Plant Equipment	583,648	25,000	558,648		-5.0%		(27,932)	(27,932)	-4.8%
Total Octillo CT Units 1-2	$17,710,503	$1,105,220	$16,605,283	-1.5%	-5.0%	($16,061)	($830,264)	($846,325)	-4.8%
Redhawk CC Units 1-2									
341.00 Structures and Improvements	$25,402,997	$4,035,739	$21,367,258	-55.6%	-5.0%	($2,243,871)	($1,068,363)	($3,312,234)	-13.0%
342.00 Fuel Holders, Products and Accessories	1,512,990		1,512,990		-5.0%		(75,650)	(75,650)	-5.0%
343.00 Prime Movers	218,047,250	42,663,478	175,383,772	6.0%	-5.0%	2,559,809	(8,769,189)	(6,209,380)	-2.8%
344.00 Generators and Devices	301,112,423	57,120,083	243,992,340	-0.7%	-5.0%	(399,841)	(12,199,617)	(12,599,458)	-4.2%
345.00 Accessory Electric Equipment	26,515,412	4,406,068	22,109,344		-5.0%		(1,105,467)	(1,105,467)	-4.2%
346.00 Miscellaneous Power Plant Equipment	693,357		693,357	-7.2%	-5.0%		(34,668)	(34,668)	-5.0%
Total Redhawk CC Units 1-2	$573,284,429	$108,225,368	$465,059,061	-0.1%	-5.0%	($83,903)	($23,252,953)	($23,336,856)	-4.1%
Saguaro									
341.00 Structures and Improvements	$1,414,380		$1,414,380		-5.0%		($70,719)	($70,719)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,451,400	146,423	1,304,977		-5.0%		(65,249)	(65,249)	-4.5%
343.00 Prime Movers	8,666,061	41,249	8,624,812		-5.0%		(431,241)	(431,241)	-5.0%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
344.00 Generators and Devices	32,947,021	434,649	32,512,372		-5.0%		(1,625,619)	(1,625,619)	-4.9%
345.00 Accessory Electric Equipment	1,759,327	60,614	1,698,713	-17.1%	-5.0%	(10,365)	(84,936)	(95,301)	-5.4%
346.00 Miscellaneous Power Plant Equipment	858,304	11,635	846,669		-5.0%		(42,333)	(42,333)	-4.9%
Total Saguaro	$47,096,493	$694,570	$46,401,923	-1.5%	-5.0%	($10,365)	($2,320,096)	($2,330,461)	-4.9%
Saguaro CT Units 1-2									
341.00 Structures and Improvements	$1,414,380		$1,414,380		-5.0%		($70,719)	($70,719)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,451,400	146,423	1,304,977		-5.0%		(65,249)	(65,249)	-4.5%
343.00 Prime Movers	8,025,154	41,249	7,983,905		-5.0%		(399,195)	(399,195)	-5.0%
344.00 Generators and Devices	4,922,637	434,649	4,487,988		-5.0%		(224,399)	(224,399)	-4.6%
345.00 Accessory Electric Equipment	1,636,774	60,614	1,576,160	-17.1%	-5.0%	(10,365)	(78,808)	(89,173)	-5.4%
346.00 Miscellaneous Power Plant Equipment	858,304	11,635	846,669		-5.0%		(42,333)	(42,333)	-4.9%
Total Saguaro CT Units 1-2	$18,308,649	$694,570	$17,614,079	-1.5%	-5.0%	($10,365)	($880,704)	($891,069)	-4.9%
Saguaro CT Unit 3									
341.00 Structures and Improvements									
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	640,907		640,907	6.0%	-5.0%		(32,045)	(32,045)	-5.0%
344.00 Generators and Devices	28,024,384		28,024,384	-8.4%	-5.0%		(1,401,219)	(1,401,219)	-5.0%
345.00 Accessory Electric Equipment	122,553		122,553	-198.7%	-5.0%		(6,128)	(6,128)	-5.0%
346.00 Miscellaneous Power Plant Equipment									
Total Saguaro CT Unit 3	$28,787,844		$28,787,844		-5.0%		($1,439,392)	($1,439,392)	-5.0%
Solar Units									
341.00 Structures and Improvements	$431,153	$12,750	$418,403	-2.1%	-5.0%	($268)	($20,920)	($21,188)	-4.9%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices	16,690,177	1,355,221	15,334,956	-8.4%	-5.0%	(113,839)	(766,748)	(880,586)	-5.3%
345.00 Accessory Electric Equipment	166,635		166,635	-198.7%	-5.0%		(8,332)	(8,332)	-5.0%
346.00 Miscellaneous Power Plant Equipment									
Total Solar Units	$17,287,965	$1,367,971	$15,919,994	-8.3%	-5.0%	($114,106)	($796,000)	($910,106)	-5.3%
Sundance									
341.00 Structures and Improvements	$12,482,674		$12,482,674		-5.0%		($624,134)	($624,134)	-5.0%
342.00 Fuel Holders, Products and Accessories	4,254,044		4,254,044		-5.0%		(212,702)	(212,702)	-5.0%
343.00 Prime Movers	229,888,056	240,000	229,648,056		-5.0%		(11,482,403)	(11,482,403)	-5.0%
344.00 Generators and Devices	297,855		297,855		-5.0%		(14,893)	(14,893)	-5.0%
345.00 Accessory Electric Equipment	25,914,410		25,914,410	-17.1%	-5.0%		(1,295,721)	(1,295,721)	-5.0%
346.00 Miscellaneous Power Plant Equipment	1,220,859		1,220,859		-5.0%		(61,043)	(61,043)	-5.0%
Total Sun Dance	$274,057,898	$240,000	$273,817,898		-5.0%		($13,690,895)	($13,690,895)	-5.0%
West Phoenix									
341.00 Structures and Improvements	$23,699,847	$197,918	$23,501,929	-39.1%	-5.0%	($77,482)	($1,175,096)	($1,252,579)	-5.3%
342.00 Fuel Holders, Products and Accessories	28,166,490	1,364,569	26,801,921	-5.6%	-5.0%	(76,416)	(1,340,096)	(1,416,512)	-5.0%
343.00 Prime Movers	186,297,277	21,482,407	164,814,870	5.9%	-5.0%	1,269,369	(8,240,744)	(6,971,375)	-3.7%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
344.00 Generators and Devices	253,471,982	21,849,417	231,622,565	-1.4%	-5.0%	(301,448)	(11,581,128)	(11,882,576)	-4.7%
345.00 Accessory Electric Equipment	30,787,542	788,057	29,999,485	-1.2%	-5.0%	(9,286)	(1,499,974)	(1,509,260)	-4.9%
346.00 Miscellaneous Power Plant Equipment	4,327,218	456,029	3,871,189	-7.7%	-5.0%	(35,114)	(193,559)	(228,674)	-5.3%
Total West Phoenix	$526,750,356	$46,138,397	$480,611,959	1.7%	-5.0%	$769,623	($24,030,598)	($23,260,975)	-4.4%
West Phoenix CC Units 1-3									
341.00 Structures and Improvements	$3,367,966	$60,860	$3,307,106	-2.1%	-5.0%	($1,278)	($165,355)	($166,633)	-4.9%
342.00 Fuel Holders, Products and Accessories	22,593,848	1,364,569	21,229,279	-5.6%	-5.0%	(76,418)	(1,061,464)	(1,137,880)	-5.0%
343.00 Prime Movers									
344.00 Generators and Devices	111,750,065	19,920,817	91,829,248	-0.7%	-5.0%	(139,446)	(4,591,462)	(4,730,908)	-4.2%
345.00 Accessory Electric Equipment	17,257,934	733,755	16,524,179		-5.0%		(826,209)	(826,209)	-4.8%
346.00 Miscellaneous Power Plant Equipment	3,216,260	456,029	2,760,231	-7.7%	-5.0%	(35,114)	(138,012)	(173,126)	-5.4%
Total West Phoenix CC Units 1-3	$158,186,073	$22,536,030	$135,650,043	-1.1%	-5.0%	($252,254)	($6,782,502)	($7,034,756)	-4.4%
West Phoenix CC Unit 4									
341.00 Structures and Improvements	$4,524,163		$4,524,163	-2.1%	-5.0%		($226,208)	($226,208)	-5.0%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109		-5.0%		(206,755)	(206,755)	-5.0%
343.00 Prime Movers	54,739,557		54,739,557	6.0%	-5.0%		(2,736,978)	(2,736,978)	-5.0%
344.00 Generators and Devices	16,032,009	771,000	15,261,009	-8.4%	-5.0%	(64,764)	(763,050)	(827,814)	-5.2%
345.00 Accessory Electric Equipment	59,871		59,871	-198.7%	-5.0%		(2,994)	(2,994)	-5.0%
346.00 Miscellaneous Power Plant Equipment	27,151		27,151	-7.2%	-5.0%		(1,358)	(1,358)	-5.0%
Total West Phoenix CC Unit 4	$79,517,860	$771,000	$78,746,860	-8.4%	-5.0%	($64,764)	($3,937,343)	($4,002,107)	-5.0%
West Phoenix CC Unit 5									
341.00 Structures and Improvements	$10,804,474		$10,804,474	-2.1%	-5.0%		($540,224)	($540,224)	-5.0%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	122,437,292	21,156,146	101,281,146	6.0%	-5.0%	1,269,369	(5,064,057)	(3,794,689)	-3.1%
344.00 Generators and Devices	120,799,246	1,157,600	119,641,646	-8.4%	-5.0%	(97,238)	(5,982,082)	(6,079,321)	-5.0%
345.00 Accessory Electric Equipment	11,706,160		11,706,160	-198.7%	-5.0%		(585,308)	(585,308)	-5.0%
346.00 Miscellaneous Power Plant Equipment	24,203		24,203	-7.2%	-5.0%		(1,210)	(1,210)	-5.0%
Total West Phoenix CC Unit 5	$265,771,375	$22,313,746	$243,457,629	5.3%	-5.0%	$1,172,130	($12,172,881)	($11,000,751)	-4.1%
West Phoenix CT Units 1-2									
341.00 Structures and Improvements	$510,951		$510,951		-5.0%		($25,548)	($25,548)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,437,533		1,437,533		-5.0%		(71,877)	(71,877)	-5.0%
343.00 Prime Movers	9,120,428	326,261	8,794,167		-5.0%		(439,708)	(439,708)	-4.8%
344.00 Generators and Devices	4,890,662		4,890,662		-5.0%		(244,533)	(244,533)	-5.0%
345.00 Accessory Electric Equipment	1,763,577	54,302	1,709,275	-17.1%	-5.0%	(9,286)	(85,464)	(94,749)	-5.4%
346.00 Miscellaneous Power Plant Equipment	1,059,604		1,059,604		-5.0%		(52,980)	(52,980)	-5.0%
Total West Phoenix CT Units 1-2	$18,782,755	$380,563	$18,402,192	-2.4%	-5.0%	($9,286)	($920,110)	($929,395)	-4.9%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
West Phoenix Common									
341.00 Structures and Improvements	$4,492,293	$137,058	$4,355,235	-55.6%	-5.0%	($76,204)	($217,762)	($293,966)	-6.5%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers									
344.00 Generators and Devices									
345.00 Accessory Electric Equipment									
346.00 Miscellaneous Power Plant Equipment									
Total West Phoenix Common	$4,492,293	$137,058	$4,355,235	-55.6%	-5.0%	($76,204)	($217,762)	($293,966)	-6.5%
Yucca CT Units 1-4									
341.00 Structures and Improvements	$548,169	$10,450	$537,719		-5.0%		($26,886)	($26,886)	-4.9%
342.00 Fuel Holders, Products and Accessories	3,287,907	42,920	3,244,987		-5.0%		(162,249)	(162,249)	-4.9%
343.00 Prime Movers	7,962,254		7,962,254		-5.0%		(398,113)	(398,113)	-5.0%
344.00 Generators and Devices	6,637,985	111,890	6,526,095		-5.0%		(326,305)	(326,305)	-4.9%
345.00 Accessory Electric Equipment	2,753,683	41,000	2,712,683	-17.1%	-5.0%	(7,011)	(135,634)	(142,645)	-5.2%
346.00 Miscellaneous Power Plant Equipment	561,193		561,193		-5.0%		(28,060)	(28,060)	-5.0%
Total Yucca CT Units 1-4	$21,751,191	$206,260	$21,544,931	-3.4%	-5.0%	($7,011)	($1,077,247)	($1,084,258)	-5.0%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/07 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (by Unit)									
Cholla									
311.00 Structures and Improvements	$57,025,813	$4,005,795	$53,020,018	-5.0%	-11.5%	($200,290)	($6,121,077)	($6,321,367)	-11.1%
312.00 Boiler Plant Equipment	350,284,053	22,989,338	327,294,715	-15.0%	-10.9%	(3,448,401)	(35,515,111)	(38,963,512)	-11.1%
314.00 Turbogenerator Units	101,616,123	6,755,259	94,860,864	-15.0%	-11.4%	(1,013,289)	(10,843,611)	(11,856,899)	-11.7%
315.00 Accessory Electric Equipment	89,687,352	6,084,438	83,602,914	-10.0%	-11.0%	(608,444)	(9,188,182)	(9,796,626)	-10.9%
316.00 Miscellaneous Power Plant Equipment	22,758,920	1,523,554	21,235,366	-15.0%	-11.2%	(228,533)	(2,378,029)	(2,606,562)	-11.5%
Total Cholla	$621,372,261	$41,358,384	$580,013,877	-13.3%	-11.0%	($5,498,956)	($64,046,010)	($69,544,966)	-11.2%
Cholla Unit 1									
311.00 Structures and Improvements	$3,648,903	$192,883	$3,456,020	-5.0%	-9.6%	($9,644)	($331,778)	($341,422)	-9.4%
312.00 Boiler Plant Equipment	68,193,466	3,499,669	64,693,797	-15.0%	-9.6%	(524,950)	(6,210,604)	(6,735,555)	-9.9%
314.00 Turbogenerator Units	11,111,084	599,083	10,512,001	-15.0%	-9.6%	(89,862)	(1,009,152)	(1,099,015)	-9.9%
315.00 Accessory Electric Equipment	7,508,911	394,875	7,114,036	-10.0%	-9.6%	(39,487)	(682,947)	(722,435)	-9.6%
316.00 Miscellaneous Power Plant Equipment	2,432,224	126,773	2,305,451	-15.0%	-9.6%	(19,016)	(221,323)	(240,339)	-9.9%
Total Cholla Unit 1	$92,894,588	$4,813,283	$88,081,305	-14.2%	-9.6%	($682,960)	($8,455,805)	($9,138,766)	-9.8%
Cholla Unit 2									
311.00 Structures and Improvements	$5,452,541	$358,580	$5,093,961	-5.0%	-9.7%	($17,929)	($494,114)	($512,043)	-9.4%
312.00 Boiler Plant Equipment	148,802,569	9,930,961	138,871,608	-15.0%	-9.7%	(1,489,644)	(13,470,546)	(14,960,190)	-10.1%
314.00 Turbogenerator Units	37,854,762	2,485,745	35,369,017	-15.0%	-9.7%	(372,862)	(3,430,795)	(3,803,656)	-10.0%
315.00 Accessory Electric Equipment	44,885,780	3,008,976	41,876,804	-10.0%	-9.7%	(300,898)	(4,062,050)	(4,362,948)	-9.7%
316.00 Miscellaneous Power Plant Equipment	5,812,164	381,776	5,430,388	-15.0%	-9.7%	(57,266)	(526,748)	(584,014)	-10.0%
Total Cholla Unit 2	$242,807,816	$16,166,039	$226,641,777	-13.8%	-9.7%	($2,238,599)	($21,984,252)	($24,222,851)	-10.0%
Cholla Unit 3									
311.00 Structures and Improvements	$9,819,620	$708,911	$9,110,709	-5.0%	-13.1%	($35,446)	($1,193,503)	($1,228,948)	-12.5%
312.00 Boiler Plant Equipment	106,408,931	7,651,566	98,757,365	-15.0%	-13.1%	(1,147,735)	(12,937,215)	(14,084,950)	-13.2%
314.00 Turbogenerator Units	51,739,505	3,606,061	48,133,444	-15.0%	-13.1%	(540,909)	(6,305,481)	(6,846,390)	-13.2%
315.00 Accessory Electric Equipment	30,765,519	2,219,914	28,545,605	-10.0%	-13.1%	(221,991)	(3,739,474)	(3,961,466)	-12.9%
316.00 Miscellaneous Power Plant Equipment	4,593,291	325,741	4,267,550	-15.0%	-13.1%	(48,861)	(559,049)	(607,910)	-13.2%
Total Cholla Unit 3	$203,326,866	$14,512,193	$188,814,673	-13.7%	-13.1%	($1,994,942)	($24,734,722)	($26,729,664)	-13.1%
Cholla Common									
311.00 Structures and Improvements	$38,104,749	$2,745,420	$35,359,329	-5.0%	-11.6%	($137,271)	($4,101,682)	($4,238,953)	-11.1%
312.00 Boiler Plant Equipment	26,879,087	1,907,141	24,971,946	-15.0%	-11.6%	(286,071)	(2,896,746)	(3,182,817)	-11.8%
314.00 Turbogenerator Units	910,772	64,370	846,402	-15.0%	-11.6%	(9,655)	(98,183)	(107,838)	-11.8%
315.00 Accessory Electric Equipment	6,527,142	460,673	6,066,469	-10.0%	-11.6%	(46,067)	(703,710)	(749,778)	-11.5%
316.00 Miscellaneous Power Plant Equipment	9,921,241	689,264	9,231,977	-15.0%	-11.6%	(103,390)	(1,070,909)	(1,174,299)	-11.8%
Total Cholla Common	$82,342,991	$5,866,868	$76,476,123	-9.9%	-11.6%	($582,455)	($8,871,230)	($9,453,685)	-11.5%
Four Corners									
311.00 Structures and Improvements	$48,283,791	$1,630,634	$46,653,157	-5.0%	-13.3%	($81,532)	($6,187,443)	($6,268,975)	-13.0%
312.00 Boiler Plant Equipment	353,157,905	12,136,438	341,021,467	-15.0%	-13.3%	(1,820,466)	(45,431,416)	(47,251,882)	-13.4%

Statement F

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Account Description	12/31/07 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
314.00 Turbogenerator Units	68,213,063	2,175,142	66,037,921	-15.0%	-12.9%	(326,271)	(8,528,472)	(8,854,743)	-13.0%
315.00 Accessory Electric Equipment	33,335,936	1,269,806	32,066,130	-10.0%	-13.9%	(126,981)	(4,451,797)	(4,578,777)	-13.7%
316.00 Miscellaneous Power Plant Equipment	24,153,428	1,000,969	23,152,459	-15.0%	-14.5%	(150,145)	(3,365,460)	(3,515,605)	-14.6%
Total Four Corners	$527,144,123	$18,212,989	$508,931,134	-13.8%	-13.4%	($2,505,395)	($67,964,588)	($70,469,983)	-13.4%
Four Corners Units 1-3									
311.00 Structures and Improvements	$32,557,195	$672,372	$31,884,823	-5.0%	-11.3%	($33,619)	($3,602,985)	($3,636,604)	-11.2%
312.00 Boiler Plant Equipment	234,692,935	4,897,118	229,795,817	-15.0%	-11.3%	(734,568)	(25,966,927)	(26,701,495)	-11.4%
314.00 Turbogenerator Units	49,894,597	1,053,239	48,841,358	-15.0%	-11.3%	(157,986)	(5,519,073)	(5,677,059)	-11.4%
315.00 Accessory Electric Equipment	19,105,566	399,503	18,706,063	-10.0%	-11.3%	(39,950)	(2,113,785)	(2,153,735)	-11.3%
316.00 Miscellaneous Power Plant Equipment	11,296,591	228,518	11,068,073	-15.0%	-11.3%	(34,278)	(1,250,692)	(1,284,970)	-11.4%
Total Four Corners Units 1-3	$347,546,884	$7,250,749	$340,296,135	-13.8%	-11.3%	($1,000,400)	($38,453,463)	($39,453,863)	-11.4%
Four Corners Units 4-5									
311.00 Structures and Improvements	$11,035,183	$669,979	$10,365,204	-5.0%	-17.5%	($33,499)	($1,813,911)	($1,847,410)	-16.7%
312.00 Boiler Plant Equipment	103,280,404	6,306,930	96,973,474	-15.0%	-17.5%	(946,040)	(16,970,358)	(17,916,397)	-17.3%
314.00 Turbogenerator Units	16,330,966	993,621	15,337,345	-15.0%	-17.5%	(149,043)	(2,684,035)	(2,833,079)	-17.3%
315.00 Accessory Electric Equipment	10,081,177	613,835	9,467,342	-10.0%	-17.5%	(61,383)	(1,656,785)	(1,718,168)	-17.0%
316.00 Miscellaneous Power Plant Equipment	3,123,482	188,934	2,934,548	-15.0%	-17.5%	(28,340)	(513,546)	(541,886)	-17.3%
Total Four Corners Units 4-5	$143,851,212	$8,773,299	$135,077,913	-13.9%	-17.5%	($1,218,305)	($23,638,635)	($24,856,940)	-17.3%
Four Corners Common									
311.00 Structures and Improvements	$4,691,413	$288,283	$4,403,130	-5.0%	-17.5%	($14,414)	($770,548)	($784,962)	-16.7%
312.00 Boiler Plant Equipment	15,184,566	932,391	14,252,175	-15.0%	-17.5%	(139,859)	(2,494,131)	(2,633,989)	-17.3%
314.00 Turbogenerator Units	1,987,500	128,282	1,859,218	-15.0%	-17.5%	(19,242)	(325,363)	(344,605)	-17.3%
315.00 Accessory Electric Equipment	4,149,193	256,468	3,892,725	-10.0%	-17.5%	(25,647)	(681,227)	(706,874)	-17.0%
316.00 Miscellaneous Power Plant Equipment	9,733,355	583,516	9,149,839	-15.0%	-17.5%	(87,527)	(1,601,222)	(1,688,749)	-17.4%
Total Four Corners Common	$35,746,027	$2,188,940	$33,557,087	-13.1%	-17.5%	($286,689)	($5,872,490)	($6,159,179)	-17.2%
Navajo Units 1-3									
311.00 Structures and Improvements	$27,580,268	$1,304,342	$26,275,926	-5.0%	-10.7%	($65,217)	($2,811,524)	($2,876,741)	-10.4%
312.00 Boiler Plant Equipment	161,702,139	7,625,875	154,076,264	-15.0%	-10.7%	(1,143,881)	(16,486,160)	(17,630,042)	-10.9%
314.00 Turbogenerator Units	24,699,305	1,190,314	23,508,991	-15.0%	-10.7%	(178,547)	(2,515,462)	(2,694,009)	-10.9%
315.00 Accessory Electric Equipment	20,805,398	999,900	19,805,498	-10.0%	-10.7%	(99,990)	(2,119,188)	(2,219,178)	-10.7%
316.00 Miscellaneous Power Plant Equipment	16,797,235	783,652	16,013,583	-15.0%	-10.7%	(117,548)	(1,713,453)	(1,831,001)	-10.9%
Total Navajo Units 1-3	$251,584,345	$11,904,084	$239,680,261	-13.5%	-10.7%	($1,605,183)	($25,645,788)	($27,250,971)	-10.8%
Ocotillo Units 1-2									
311.00 Structures and Improvements	$3,796,298	$120,616	$3,675,682	-5.0%	-30.6%	($6,031)	($1,124,759)	($1,130,790)	-29.8%
312.00 Boiler Plant Equipment	24,502,039	798,382	23,703,657	-15.0%	-30.6%	(119,757)	(7,253,319)	(7,373,076)	-30.1%
314.00 Turbogenerator Units	15,372,486	507,408	14,865,078	-15.0%	-30.6%	(76,111)	(4,548,714)	(4,624,825)	-30.1%
315.00 Accessory Electric Equipment	2,859,128	93,810	2,765,318	-10.0%	-30.6%	(9,381)	(846,187)	(855,568)	-29.9%
316.00 Miscellaneous Power Plant Equipment	5,544,025	170,156	5,373,869	-15.0%	-30.6%	(25,523)	(1,644,404)	(1,669,927)	-30.1%
Total Ocotillo Units 1-2	$52,073,976	$1,690,371	$50,383,605	-14.0%	-30.6%	($236,804)	($15,417,383)	($15,654,187)	-30.1%

Statement F

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Account Description	12/31/07 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Saguaro Units 1-2									
311.00 Structures and Improvements	$3,048,470	$97,958	$2,950,512	-5.0%	-30.0%	($4,898)	($885,154)	($890,052)	-29.2%
312.00 Boiler Plant Equipment	22,899,016	742,039	22,156,977	-15.0%	-30.0%	(111,306)	(6,647,093)	(6,758,399)	-29.5%
314.00 Turbogenerator Units	16,513,563	537,675	15,975,888	-15.0%	-30.0%	(80,651)	(4,792,766)	(4,873,418)	-29.5%
315.00 Accessory Electric Equipment	4,922,271	155,652	4,766,619	-10.0%	-30.0%	(15,565)	(1,429,986)	(1,445,551)	-29.4%
316.00 Miscellaneous Power Plant Equipment	3,297,526	102,597	3,194,929	-15.0%	-30.0%	(15,390)	(958,479)	(973,868)	-29.5%
Total Saguaro Units 1-2	$50,680,846	$1,635,921	$49,044,925	-13.9%	-30.0%	($227,810)	($14,713,477)	($14,941,287)	-29.5%
NUCLEAR PRODUCTION (by Unit)									
Palo Verde									
321.00 Structures and Improvements	$657,537,995	$31,120,897	$626,417,098	-5.0%		($1,556,045)		($1,556,045)	-0.2%
322.00 Reactor Plant Equipment	1,014,755,344	45,880,680	968,874,664	-15.0%		(6,882,102)		(6,882,102)	-0.7%
322.10 Steam Generators	25,412,774	1,268,972	24,143,802	-15.0%		(190,346)		(190,346)	-0.7%
323.00 Turbogenerator Units	346,650,191	15,909,781	330,740,410	-5.0%		(795,489)		(795,489)	-0.2%
324.00 Accessory Electric Equipment	272,678,334	12,468,940	260,209,394	-5.0%		(623,447)		(623,447)	-0.2%
325.00 Miscellaneous Power Plant Equipment	137,397,362	6,447,970	130,949,392	-5.0%		(322,398)		(322,398)	-0.2%
Total Palo Verde	$2,454,432,000	$113,097,239	$2,341,334,761	-9.2%		($10,369,827)		($10,369,827)	-0.4%
Palo Verde Unit 1									
321.00 Structures and Improvements	$155,161,288	$6,551,654	$148,609,634	-5.0%		($327,583)		($327,583)	-0.2%
322.00 Reactor Plant Equipment	436,859,649	18,289,062	418,570,587	-15.0%		(2,743,359)		(2,743,359)	-0.6%
322.10 Steam Generators									
323.00 Turbogenerator Units	121,659,550	5,107,214	116,552,336	-5.0%		(255,361)		(255,361)	-0.2%
324.00 Accessory Electric Equipment	114,704,738	4,844,419	109,860,319	-5.0%		(242,221)		(242,221)	-0.2%
325.00 Miscellaneous Power Plant Equipment	30,135,442	1,269,009	28,866,433	-5.0%		(63,450)		(63,450)	-0.2%
Total Palo Verde Unit 1	$858,520,667	$36,061,359	$822,459,308	-10.1%		($3,631,974)		($3,631,974)	-0.4%
Palo Verde Unit 2									
321.00 Structures and Improvements	$90,571,765	$4,060,704	$86,511,061	-5.0%		($203,035)		($203,035)	-0.2%
322.00 Reactor Plant Equipment	226,769,607	10,082,060	216,687,547	-15.0%		(1,512,309)		(1,512,309)	-0.7%
322.10 Steam Generators									
323.00 Turbogenerator Units	77,670,724	3,464,434	74,206,290	-5.0%		(173,222)		(173,222)	-0.2%
324.00 Accessory Electric Equipment	50,017,128	2,239,060	47,778,068	-5.0%		(111,953)		(111,953)	-0.2%
325.00 Miscellaneous Power Plant Equipment	26,812,162	1,190,201	25,621,961	-5.0%		(59,510)		(59,510)	-0.2%
Total Palo Verde Unit 2	$471,841,386	$21,036,459	$450,804,927	-9.8%		($2,060,029)		($2,060,029)	-0.4%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam Production

Statement F

Account Description	12/31/07 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Palo Verde Unit 3									
321.00 Structures and Improvements	$160,295,268	$7,999,319	$152,295,949	-5.0%		($399,966)		($399,966)	-0.2%
322.00 Reactor Plant Equipment	324,634,368	16,189,356	308,445,012	-15.0%		(2,428,403)		(2,428,403)	-0.7%
322.10 Steam Generators	25,412,774	1,268,972	24,143,802	-15.0%		(190,346)		(190,346)	-0.7%
323.00 Turbogenerator Units	144,937,168	7,223,222	137,713,946	-5.0%		(361,161)		(361,161)	-0.2%
324.00 Accessory Electric Equipment	89,475,454	4,464,406	85,011,048	-5.0%		(223,220)		(223,220)	-0.2%
325.00 Miscellaneous Power Plant Equipment	27,650,635	1,376,165	26,274,470	-5.0%		(68,808)		(68,808)	-0.2%
Total Palo Verde Unit 3	$772,405,667	$38,521,440	$733,884,227	-9.5%		($3,671,905)		($3,671,905)	-0.5%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$140,178,050	$6,973,869	$133,204,181	-5.0%		($348,693)		($348,693)	-0.2%
322.00 Reactor Plant Equipment	133,326	6,437	126,889	-15.0%		(965)		(965)	-0.7%
322.10 Steam Generators									
323.00 Turbogenerator Units	217,756	10,819	206,937	-5.0%		(541)		(541)	-0.2%
324.00 Accessory Electric Equipment									
325.00 Miscellaneous Power Plant Equipment	88,819	4,401	84,418	-5.0%		(220)		(220)	-0.2%
Total Palo Verde Water Reclamation	$140,617,951	$6,995,526	$133,622,425	-5.0%		($350,420)		($350,420)	-0.2%
Palo Verde Common									
321.00 Structures and Improvements	$111,331,624	$5,535,350	$105,796,274	-5.0%		($276,767)		($276,767)	-0.2%
322.00 Reactor Plant Equipment	26,358,394	1,313,766	25,044,628	-15.0%		(197,065)		(197,065)	-0.7%
322.10 Steam Generators									
323.00 Turbogenerator Units	2,164,993	104,092	2,060,901	-5.0%		(5,205)		(5,205)	-0.2%
324.00 Accessory Electric Equipment	18,481,014	921,055	17,559,959	-5.0%		(46,053)		(46,053)	-0.2%
325.00 Miscellaneous Power Plant Equipment	52,710,304	2,608,193	50,102,111	-5.0%		(130,410)		(130,410)	-0.2%
Total Palo Verde Common	$211,046,329	$10,482,455	$200,563,874	-6.3%		($655,499)		($655,499)	-0.3%

ARIZONA PUBLIC SERVICE COMPANY Statement G

Dismantlement Costs
Steam Production

Unit	Capacity (MW)	Cost per kW	2002 Cost	Plant	Distributed Cost	Inflation Rate	Year Spent	Trended Cost	Accrual Rate
A	B	C	D=B*C*1000	E	F	G	H	I	J=I/E
Cholla									
1	110	40.00	$4,400,000	$88,081,305	$3,819,850	3.00%	2028	$8,484,991	9.6%
2	245	40.00	9,800,000	226,641,777	8,507,848	3.00%	2033	21,908,413	9.7%
3	260	40.00	10,400,000	188,814,673	9,028,737	3.00%	2035	24,665,654	13.1%
C				76,476,123	3,243,565	3.00%	2035	8,861,112	11.6%
	615		$24,600,000	$580,013,877	$24,600,000			$63,920,170	11.0%
	Allocated to Common:		3,243,565						
	Allocated to Units:		$21,356,435						
Four Corners									
1-3	560	47.00	$26,320,000	$340,296,135	$24,584,554	3.00%	2016	$38,301,934	11.3%
4-5	222	47.00	10,434,000	135,077,913	9,746,020	3.00%	2031	23,656,148	17.5%
C				33,557,087	2,423,426	3.00%	2031	5,882,292	17.5%
	782		$36,754,000	$508,931,134	$36,754,000			$67,840,374	13.3%
	Allocated to Common:		2,423,426						
	Allocated to Units:		$34,330,574						
Navajo									
1-3	315	39.00	$12,285,000	$239,680,261	$12,285,000	3.00%	2026	$25,722,062	10.7%
C									
	315		$12,285,000	$239,680,261	$12,285,000			$25,722,062	10.7%
	Allocated to Common:								
	Allocated to Units:		$12,285,000						
Ocotillo									
1-2	220	40.00	$8,800,000	$50,383,605	$8,800,000	3.00%	2020	$15,430,853	30.6%
C									
	220		$8,800,000	$50,383,605	$8,800,000			$15,430,853	30.6%
	Allocated to Common:								
	Allocated to Units:		$8,800,000						
Saguaro									
1-2	210	40.00	$8,400,000	$49,044,925	$8,400,000	3.00%	2020	$14,729,451	30.0%
C									
	210		$8,400,000	$49,044,925	$8,400,000			$14,729,451	30.0%
	Allocated to Common:								
	Allocated to Units:		$8,400,000						
Palo Verde									
1	1243			$822,459,308		3.00%	2024		
2	1335			450,804,927		3.00%	2025		
3	1247			733,884,227		3.00%	2027		
WR				133,622,425		3.00%	2027		
C				200,563,874		3.00%	2027		
	3825			$2,341,334,761					
	Allocated to WR:								
	Allocated to Common:								
	Allocated to Units:								

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
311.00 Structures and Improvements									29.65	15.98	-12.4	-12.5
312.00 Boiler Plant Equipment									29.61	15.86	-13.3	-12.9
314.00 Turbogenerator Units									30.43	16.74	-13.3	-14.5
315.00 Accessory Electric Equipment									36.69	18.96	-12.5	-12.5
316.00 Miscellaneous Power Plant Equipment									24.68	16.13	-14.7	-14.6
Total Steam Production Plant									30.03	16.27	-13.2	-13.2
NUCLEAR PRODUCTION												
321.00 Structures and Improvements									35.64	18.08	-0.3	
322.00 Reactor Plant Equipment									32.76	17.25	-1.8	
322.10 Steam Generators									37.57	19.00	-0.7	
323.00 Turbogenerator Units									33.89	17.51	-0.5	
324.00 Accessory Electric Equipment									36.45	17.44	-0.3	
325.00 Miscellaneous Power Plant Equipment									32.54	18.02	-1.2	
Total Nuclear Production Plant									34.07	17.58	-1.0	-0.4
OTHER PRODUCTION												
341.00 Structures and Improvements									31.62	26.20	-8.3	
342.00 Fuel Holders, Products and Accessories									29.27	20.86	-5.0	
343.00 Prime Movers									32.42	27.75	-3.9	
344.00 Generators and Devices									29.70	24.48	-4.5	
345.00 Accessory Electric Equipment									30.71	25.07	-4.8	
346.00 Miscellaneous Power Plant Equipment									29.32	18.61	-5.1	
Total Other Production Plant									31.01	25.85	-4.4	-5.0

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
TRANSMISSION PLANT												
352.02 Structures and Improvements	50.00	R4	50.00	21.69		-5.0	50.00	R4	50.38	19.18		
353.00 Station Equipment	57.00	R1.5	57.00	39.98			45.00	S0.5	45.98	33.50		
354.00 Towers and Fixtures	60.00	R3	60.00	42.49		-35.0	60.00	R3	60.18	39.78		
355.00 Poles and Fixtures	60.00	R3	60.00	18.51		-15.0	50.00	R1.5	50.08	45.43	-20.0	-20.0
356.00 Overhead Conductors and Devices	55.00	R3	55.00	37.51		-35.0	60.00	R3	59.90	50.16	18.7	20.0
Total Transmission Plant									46.48	34.05	0.1	0.1
DISTRIBUTION PLANT												
361.00 Structures and Improvements	45.00	R2.5	45.00	33.18	-10.0	-10.0	60.00	R3	59.87	47.22	-4.6	-5.0
362.00 Station Equipment	44.00	L0.5	44.00	36.73			43.00	L0.5	43.08	36.31	10.0	10.0
364.01 Poles, Towers and Fixtures - Wood	38.00	R0.5	38.00	29.41	-10.0	-10.0	40.00	L0	39.92	31.55	-0.5	-5.0
364.02 Poles, Towers and Fixtures - Steel	50.00	R3	50.00	46.78	-5.0	-5.0	35.00	L0.5	35.08	31.88	-5.7	-5.0
365.00 Overhead Conductors and Devices	53.00	O1	53.00	46.65	-10.0	-10.0	50.00	SC	49.97	43.42	10.2	10.0
366.00 Underground Conduit	86.00	O1	86.00	82.10	-5.0	-5.0	65.00	L1	64.94	56.80	-5.0	-5.0
367.00 Underground Conductors and Devices	29.00	L1	29.00	22.28	-5.0	-5.0	33.00	L1	32.94	26.28	-4.2	-5.0
368.00 Line Transformers	36.00	R3	36.00	23.63	-5.0	-5.0	55.00	L1	55.14	44.80	-4.3	-5.0
369.00 Services	37.00	S2	37.00	26.72	-10.0	-10.0	40.00	L1	40.47	31.15		
370.01 Meters - Electronic	26.00	R1.5	26.00	23.06			5.00	SQ	5.00	2.71		
370.02 Meters - Electromechanical	29.00	L0.5	29.00	21.24			5.00	SQ	5.00	3.50		
370.03 Meters - AMI	26.00	R1.5	26.00				26.00	R1.5	26.00	25.47		
371.00 Installations on Customers' Premises	50.00	O2	50.00	45.48	-20.0	-20.0	55.00	SC	54.77	49.26	-10.6	-10.0
373.00 Street Lighting and Signal Systems	35.00	R2.5	35.00	24.32	-20.0	-20.0	65.00	L0	64.65	57.06	-9.1	-10.0
Total Distribution Plant									32.71	26.67	-1.5	-2.4
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	39.00	R1	39.00	29.54	-15.0	-15.0	45.00	L1	45.03	34.14	-5.3	-5.0
391.CM Office Furn. and Equip. - Computer	8.00	R3	8.00	4.28			8.00	L3	8.09	4.69	-0.1	
392.EL Transportation Equipment - Electric Vehicles							12.00	L0	13.95	7.88	-0.1	
392.HD Transportation Equipment - Heavy Duty							20.00	R4	21.23	7.04	-3.0	
392.LD Transportation Equipment - Light Duty							7.00	O3	9.01	6.64	16.5	15.0
392.MD Transportation Equipment - Medium Duty							15.00	L2	17.19	6.60		

ARIZONA PUBLIC SERVICE COMPANY

Present and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Present Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2007) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
392.TR Transportation Equipment - Trailers							30.00	SC	33.38	20.51		
396.00 Power Operated Equipment							17.00	L2	17.86	7.71	3.0	3.0
397.00 Communication Equipment	19.00	S1.5	19.00	11.53			18.00	S1.5	18.04	11.17		
Total Depreciable									16.54	10.78	-0.3	-0.9
Amortizable												
391.FE Office Furn. and Equip. - Furniture	20.00	SQ	20.00	12.23			20.00	SQ	20.00	11.65		
393.00 Stores Equipment	20.00	SQ	20.00	2.14			20.00	SQ	20.00	2.73		
394.00 Tools, Shop and Garage Equipment	20.00	SQ	20.00	12.20			20.00	SQ	20.00	12.39		
395.00 Laboratory Equipment	20.00	L1	20.00	11.99			20.00	SQ	20.00	7.31		
398.00 Miscellaneous Equipment	24.00	S1.5	24.00	20.91			24.00	SQ	24.00	19.34		
Total Amortizable									20.42	12.41		
Total General Plant									17.20	11.06	-0.3	-0.7
TOTAL UTILITY									31.24	21.69	-3.4	-3.8
STEAM PRODUCTION (by Unit)												
Cholla												
311.00 Structures and Improvements									46.39	25.69	-11.0	-11.1
312.00 Boiler Plant Equipment									39.52	23.80	-11.5	-11.1
314.00 Turbogenerator Units									36.92	25.19	-10.2	-11.6
315.00 Accessory Electric Equipment									45.73	24.80	-11.0	-10.9
316.00 Miscellaneous Power Plant Equipment									37.20	25.30	-11.9	-11.4
Total Cholla									40.30	24.39	-11.2	-11.2
Cholla Unit 1												
311.00 Structures and Improvements	2017	75-S1.5		11.97	-15.8	-15.8	2028	200-SC	32.37	19.96	-9.1	-9.4
312.00 Boiler Plant Equipment	2017	48-L2		11.20	-16.3	-16.3	2028	200-SC	24.87	19.97	-10.2	-9.9
314.00 Turbogenerator Units	2017	65-R2		11.90	-15.8	-15.8	2028	200-SC	40.13	19.94	-9.7	-9.9
315.00 Accessory Electric Equipment	2017	60-R2.5		11.86	-15.9	-15.9	2028	200-SC	30.87	19.96	-9.6	-9.6
316.00 Miscellaneous Power Plant Equipment	2017	40-R2		11.63	-16.1	-16.1	2028	200-SC	33.42	19.96	-9.9	-9.9
Total Cholla Unit 1									26.94	19.97	-10.1	-9.9

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Cholla Unit 2												
311.00 Structures and Improvements	2033	75-S1.5		26.78	-18.1	-18.1	2033	200-SC	40.34	24.65	-9.3	-9.4
312.00 Boiler Plant Equipment	2033	48-L2		20.46	-19.0	-19.0	2033	200-SC	46.13	24.64	-10.4	-10.1
314.00 Turbogenerator Units	2033	65-R2		25.56	-18.3	-18.3	2033	200-SC	38.06	24.66	-9.1	-10.0
315.00 Accessory Electric Equipment	2033	60-R2.5		25.09	-18.4	-18.4	2033	200-SC	48.20	24.63	-9.7	-9.7
316.00 Miscellaneous Power Plant Equipment	2033	40-R2		20.74	-19.1	-19.1	2033	200-SC	39.88	24.65	-10.3	-10.0
Total Cholla Unit 2									44.70	24.64	-10.0	-10.0
Cholla Unit 3												
311.00 Structures and Improvements	2035	75-S1.5		27.97	-21.7	-21.7	2035	200-SC	50.03	26.49	-12.5	-12.5
312.00 Boiler Plant Equipment	2035	48-L2		21.56	-20.9	-20.9	2035	200-SC	47.58	26.50	-13.4	-13.2
314.00 Turbogenerator Units	2035	65-R2		28.16	-21.8	-21.8	2035	200-SC	35.50	26.53	-11.2	-13.2
315.00 Accessory Electric Equipment	2035	60-R2.5		26.87	-21.5	-21.5	2035	200-SC	49.74	26.49	-12.9	-12.9
316.00 Miscellaneous Power Plant Equipment	2035	40-R2		21.91	-20.8	-20.8	2035	200-SC	42.25	26.51	-13.4	-13.2
Total Cholla Unit 3									44.04	26.51	-12.6	-13.1
Cholla Common												
311.00 Structures and Improvements	2035	75-S1.5		28.01	-18.9	-18.9	2035	200-SC	48.54	26.49	-11.0	-11.1
312.00 Boiler Plant Equipment	2035	48-L2		23.38	-19.3	-19.3	2035	200-SC	40.70	26.51	-13.2	-11.8
314.00 Turbogenerator Units	2035	65-R2		27.18	-19.0	-19.0	2035	200-SC	39.11	26.52	-8.1	-11.8
315.00 Accessory Electric Equipment	2035	60-R2.5		27.19	-19.0	-19.0	2035	200-SC	38.82	26.52	-11.6	-11.5
316.00 Miscellaneous Power Plant Equipment	2035	40-R2		24.23	-19.3	-19.3	2035	200-SC	34.87	26.53	-12.4	-11.8
Total Cholla Common									42.86	26.51	-12.0	-11.5
Four Corners												
311.00 Structures and Improvements									19.89	10.73	-12.9	-13.0
312.00 Boiler Plant Equipment									22.76	10.92	-13.9	-13.4
314.00 Turbogenerator Units									21.14	10.46	-12.2	-13.0
315.00 Accessory Electric Equipment									25.35	12.24	-13.7	-13.7
316.00 Miscellaneous Power Plant Equipment									18.51	12.26	-14.7	-14.6
Total Four Corners									22.16	10.99	-13.6	-13.4

ARIZONA PUBLIC SERVICE COMPANY

Present and Proposed Parameters

Vintage Group Procedure

Statement H

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Four Corners Units 1-3												
311.00 Structures and Improvements	2016	75-S1.5		11.39	-14.1	-14.1	2016	200-SC	16.00	8.41	-11.1	-11.2
312.00 Boiler Plant Equipment	2016	48-L2		10.76	-14.8	-14.8	2016	200-SC	18.33	8.41	-12.3	-11.4
314.00 Turbogenerator Units	2016	65-R2		11.08	-14.5	-14.5	2016	200-SC	18.04	8.41	-10.8	-11.4
315.00 Accessory Electric Equipment	2016	60-R2.5		11.21	-14.3	-14.3	2016	200-SC	19.82	8.41	-11.4	-11.3
316.00 Miscellaneous Power Plant Equipment	2016	40-R2		11.15	-14.4	-14.4	2016	200-SC	11.82	8.41	-11.8	-11.4
Total Four Corners Units 1-3									17.80	8.41	-11.9	-11.4
Four Corners Units 4-5												
311.00 Structures and Improvements	2031	75-S1.5		24.80	-26.8	-26.8	2031	200-SC	39.25	22.78	-16.7	-16.7
312.00 Boiler Plant Equipment	2031	48-L2		20.40	-24.1	-24.1	2031	200-SC	43.59	22.77	-17.3	-17.3
314.00 Turbogenerator Units	2031	65-R2		24.09	-26.4	-26.4	2031	200-SC	38.14	22.78	-16.6	-17.3
315.00 Accessory Electric Equipment	2031	60-R2.5		24.24	-26.4	-26.4	2031	200-SC	41.28	22.77	-16.9	-17.0
316.00 Miscellaneous Power Plant Equipment	2031	40-R2		20.22	-23.8	-23.8	2031	200-SC	38.12	22.78	-17.3	-17.3
Total Four Corners Units 4-5									42.25	22.77	-17.2	-17.2
Four Corners Common												
311.00 Structures and Improvements	2031	75-S1.5		24.71	-29.0	-29.0	2031	200-SC	42.23	22.77	-16.2	-16.7
312.00 Boiler Plant Equipment	2031	48-L2		19.62	-25.3	-25.3	2031	200-SC	44.03	22.77	-17.5	-17.3
314.00 Turbogenerator Units	2031	65-R2		21.73	-26.4	-26.4	2031	200-SC	61.58	22.73	-12.5	-17.3
315.00 Accessory Electric Equipment	2031	60-R2.5		20.44	-25.2	-25.2	2031	200-SC	38.90	22.78	-16.5	-17.0
316.00 Miscellaneous Power Plant Equipment	2031	40-R2		21.37	-25.8	-25.8	2031	200-SC	36.42	22.78	-17.4	-17.4
Total Four Corners Common									41.46	22.77	-16.8	-17.2
Navajo Units 1-3												
311.00 Structures and Improvements	2026	75-S1.5		20.78	-14.5	-14.5	2026	200-SC	33.77	18.05	-10.4	-10.4
312.00 Boiler Plant Equipment	2026	48-L2		18.52	-15.8	-15.8	2026	200-SC	32.09	18.06	-11.2	-10.9
314.00 Turbogenerator Units	2026	65-R2		20.00	-14.9	-14.9	2026	200-SC	40.76	18.05	-10.9	-10.9
315.00 Accessory Electric Equipment	2026	60-R2.5		19.88	-15.1	-15.1	2026	200-SC	38.85	18.05	-10.7	-10.7
316.00 Miscellaneous Power Plant Equipment	2026	40-R2		18.57	-15.9	-15.9	2026	200-SC	28.67	18.06	-11.1	-10.9
Total Navajo Units 1-3									33.18	18.06	-11.1	-10.8

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Ocotillo Units 1-2												
311.00 Structures and Improvements	2020	75-S1.5		15.05	-37.9	-37.9	2020	200-SC	28.48	12.30	-28.4	-29.8
312.00 Boiler Plant Equipment	2020	48-L2		12.89	-32.9	-32.9	2020	200-SC	36.48	12.29	-30.0	-30.1
314.00 Turbogenerator Units	2020	65-R2		14.30	-36.1	-36.1	2020	200-SC	39.20	12.29	-29.9	-30.1
315.00 Accessory Electric Equipment	2020	60-R2.5		13.90	-35.0	-35.0	2020	200-SC	32.94	12.29	-29.1	-29.9
316.00 Miscellaneous Power Plant Equipment	2020	40-R2		14.61	-36.8	-36.8	2020	200-SC	19.18	12.30	-28.9	-30.1
Total Ocotillo Units 1-2									33.11	12.29	-29.7	-30.1
Saguaro Units 1-2												
311.00 Structures and Improvements	2014	75-S1.5		9.28	-29.0	-29.0	2020	200-SC	28.81	12.30	-28.7	-29.2
312.00 Boiler Plant Equipment	2014	48-L2		8.61	-27.8	-27.8	2020	200-SC	31.48	12.29	-29.1	-29.5
314.00 Turbogenerator Units	2014	65-R2		9.15	-28.8	-28.8	2020	200-SC	35.65	12.29	-28.9	-29.5
315.00 Accessory Electric Equipment	2014	60-R2.5		8.99	-28.5	-28.5	2020	200-SC	21.05	12.30	-29.0	-29.4
316.00 Miscellaneous Power Plant Equipment	2014	40-R2		8.96	-28.4	-28.4	2020	200-SC	22.35	12.30	-29.3	-29.5
Total Saguaro Units 1-2									30.21	12.29	-29.0	-29.5
NUCLEAR PRODUCTION (by Unit)												
Palo Verde												
321.00 Structures and Improvements									35.64	18.08	-0.3	-0.2
322.00 Reactor Plant Equipment									32.76	17.25	-1.8	-0.7
322.10 Steam Generators									37.57	19.00	-0.7	-0.7
323.00 Turbogenerator Units									33.89	17.51	-0.5	-0.2
324.00 Accessory Electric Equipment									36.45	17.44	-0.3	-0.2
325.00 Miscellaneous Power Plant Equipment									32.54	18.02	-1.2	-0.2
Total Palo Verde									34.07	17.58	-1.0	-0.4
Palo Verde Unit 1												
321.00 Structures and Improvements	2024	65-R2.5		18.78			2024	200-SC	36.00	16.14	-0.3	-0.2
322.00 Reactor Plant Equipment	2024	70-R1		18.37	-0.2	-0.2	2024	200-SC	30.70	16.15	-1.4	-0.6
322.10 Steam Generators	2005	25-SQ		1.00								
323.00 Turbogenerator Units	2024	60-S0		17.81	-0.4	-0.4	2024	200-SC	32.10	16.14	-0.5	-0.2

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
324.00 Accessory Electric Equipment	2024	45-R3		17.80	-0.4	-0.4	2024	200-SC	36.20	16.14	-0.3	-0.2
325.00 Miscellaneous Power Plant Equipment	2024	35-R0.5		15.87	-0.8	-0.8	2024	200-SC	33.60	16.14	-0.8	-0.2
Total Palo Verde Unit 1									32.53	16.15	-0.9	-0.4
Palo Verde Unit 2												
321.00 Structures and Improvements	2025	65-R2.5		19.70			2025	200-SC	36.57	17.10	-0.2	-0.2
322.00 Reactor Plant Equipment	2025	70-R1		19.32	-0.2	-0.2	2025	200-SC	31.73	17.10	-2.7	-0.7
322.10 Steam Generators	2003	25-SQ										
323.00 Turbogenerator Units	2025	60-S0		18.74	-0.4	-0.4	2025	200-SC	33.34	17.10	-0.6	-0.2
324.00 Accessory Electric Equipment	2025	45-R3		18.71	-0.5	-0.5	2025	200-SC	36.15	17.10	-0.3	-0.2
325.00 Miscellaneous Power Plant Equipment	2025	35-R0.5		16.82	-0.7	-0.7	2025	200-SC	32.11	17.10	-0.6	-0.2
Total Palo Verde Unit 2									33.29	17.10	-1.5	-0.4
Palo Verde Unit 3												
321.00 Structures and Improvements	2027	65-R2.5		21.58			2027	200-SC	37.18	19.00	-0.2	-0.2
322.00 Reactor Plant Equipment	2027	70-R1		21.03	-0.3	-0.3	2027	200-SC	36.61	19.00	-1.6	-0.7
322.10 Steam Generators	2007	25-SQ		2.50			2027	200-SC	37.57	19.00	-0.7	-0.7
323.00 Turbogenerator Units	2027	60-S0		20.33	-0.4	-0.4	2027	200-SC	36.19	19.00	-0.3	-0.2
324.00 Accessory Electric Equipment	2027	45-R3		20.40	-0.5	-0.5	2027	200-SC	37.11	19.00	-0.3	-0.2
325.00 Miscellaneous Power Plant Equipment	2027	35-R0.5		17.88	-0.8	-0.8	2027	200-SC	35.13	19.00	-0.6	-0.2
Total Palo Verde Unit 3									36.68	19.00	-0.9	-0.4
Palo Verde Water Reclamation												
321.00 Structures and Improvements	2027	65-R2.5		21.55			2027	200-SC	34.15	19.00	-0.5	-0.2
322.00 Reactor Plant Equipment	2027	70-R1		21.36	-0.2	-0.2	2027	200-SC	25.15	19.02	-0.7	-0.7
322.10 Steam Generators												
323.00 Turbogenerator Units	2027	60-S0		20.51	-0.4	-0.4	2027	200-SC	34.08	19.00	-0.6	-0.2
324.00 Accessory Electric Equipment												
325.00 Miscellaneous Power Plant Equipment	2027	35-R0.5		18.15	-0.8	-0.8	2027	200-SC	34.30	19.00	-1.7	-0.2
Total Palo Verde Water Reclamation									34.14	19.00	-0.5	-0.2
Palo Verde Common												
321.00 Structures and Improvements	2027	65-R2.5		21.59			2027	200-SC	34.28	19.00	-0.5	-0.2
322.00 Reactor Plant Equipment	2027	70-R1		21.05	-0.3	-0.3	2027	200-SC	36.09	19.00	-2.7	-0.7

ARIZONA PUBLIC SERVICE COMPANY

Present and Proposed Parameters

Vintage Group Procedure

Statement H

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
322.10 Steam Generators												
323.00 Turbogenerator Units	2027	60-S0		20.63	-0.4	-0.4	2027	200-SC	22.36	19.02	-1.3	-0.2
324.00 Accessory Electric Equipment	2027	45-R3		20.36	-0.5	-0.5	2027	200-SC	35.75	19.00	-0.4	-0.2
325.00 Miscellaneous Power Plant Equipment	2027	35-R0.5		18.04	-0.8	-0.8	2027	200-SC	30.99	19.01	-1.8	-0.2
Total Palo Verde Common									33.54	19.00	-1.2	-0.3
OTHER PRODUCTION (by Unit)												
Douglas CT												
341.00 Structures and Improvements	2017	80-S1		12.01	-5.0	-5.0	2020	200-SC	15.72	12.30	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		12.08	-5.0	-5.0	2020	200-SC	32.83	12.29	-4.3	-5.0
343.00 Prime Movers	2017	70-L1.5		11.65			2020	200-SC	46.12	12.29	-5.0	-5.0
344.00 Generators and Devices	2017	37-R3		8.41			2020	200-SC	46.70	12.29	-5.0	-5.0
345.00 Accessory Electric Equipment	2017	50-S2		11.06			2020	200-SC	42.17	12.29	-5.5	-5.0
346.00 Miscellaneous Power Plant Equipment	2017	70-L1		11.86			2020	200-SC	34.39	12.29	-5.0	-5.0
Total Douglas CT									42.49	12.29	-5.0	-5.0
Ocotillo CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		12.12	-5.0	-5.0	2020	200-SC	32.43	12.29	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		12.11	-5.0	-5.0	2020	200-SC	33.24	12.29	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		11.73			2020	200-SC	40.66	12.29	-4.9	-5.0
344.00 Generators and Devices	2017	37-R3		11.60			2020	200-SC	24.36	12.30	-4.4	-5.0
345.00 Accessory Electric Equipment	2017	50-S2		11.29			2020	200-SC	35.70	12.29	-5.7	-5.0
346.00 Miscellaneous Power Plant Equipment	2017	70-L1		11.81			2020	200-SC	34.75	12.29	-4.8	-5.0
Total Octillo CT Units 1-2									31.07	12.30	-4.8	-5.0
Redhawk CC Units 1-2												
341.00 Structures and Improvements	2057	70-O4		33.94	-3.0	-3.0	2037	200-SC	32.73	28.40	-13.0	-5.0
342.00 Fuel Holders, Products and Accessories				33.94	-3.0	-3.0	2037	200-SC	28.88	28.41	-5.0	-5.0
343.00 Prime Movers	2057	70-O4		33.94	-3.0	-3.0	2037	200-SC	33.06	28.40	-2.8	-5.0
344.00 Generators and Devices	2057	70-O4		33.94	-3.0	-3.0	2037	200-SC	32.63	28.40	-4.2	-5.0
345.00 Accessory Electric Equipment	2057	70-O4		33.94	-3.0	-3.0	2037	200-SC	32.92	28.40	-4.2	-5.0
346.00 Miscellaneous Power Plant Equipment				33.94	-3.0	-3.0	2037	200-SC	30.34	28.41	-5.0	-5.0
Total Redhawk CC Units 1-2									32.79	28.40	-4.1	-5.0

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Saguaro												
341.00 Structures and Improvements									21.77	12.30	-5.0	
342.00 Fuel Holders, Products and Accessories									35.77	12.29	-4.5	
343.00 Prime Movers									39.66	13.71	-5.0	
344.00 Generators and Devices									30.90	25.10	-4.9	
345.00 Accessory Electric Equipment									39.91	13.67	-5.4	
346.00 Miscellaneous Power Plant Equipment									24.45	12.30	-4.9	
Total Saguaro									32.04	21.85	-4.9	-5.0
Saguaro CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		12.34	-5.0	-5.0	2020	200-SC	21.77	12.30	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		12.00	-5.0	-5.0	2020	200-SC	35.77	12.29	-4.5	-5.0
343.00 Prime Movers	2017	70-L1.5		11.77			2020	200-SC	40.25	12.29	-5.0	-5.0
344.00 Generators and Devices	2017	37-R3		10.88			2020	200-SC	20.79	12.30	-4.6	-5.0
345.00 Accessory Electric Equipment	2017	50-S2		11.28			2020	200-SC	40.51	12.29	-5.4	-5.0
346.00 Miscellaneous Power Plant Equipment	2017	70-L1		12.00			2020	200-SC	24.45	12.30	-4.9	-5.0
Total Saguaro CT Units 1-2									29.89	12.30	-4.9	-5.0
Saguaro CT Unit 3												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2047	37-R3		33.54			2037	200-SC	33.51	28.40	-5.0	-5.0
344.00 Generators and Devices	2047	37-R3		33.54			2037	200-SC	33.51	28.40	-5.0	-5.0
345.00 Accessory Electric Equipment	2047	37-R3		33.54			2037	200-SC	33.51	28.40	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment												
Total Saguaro CT Unit 3									33.51	28.40	-5.0	-5.0
Solar Units												
341.00 Structures and Improvements	12.00	SQ		2.03			12.00	S3	14.32	3.20	-4.9	-5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers												

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
344.00 Generators and Devices	12.00	SQ		7.56			12.00	S3	12.12	5.48	-5.3	-5.0
345.00 Accessory Electric Equipment	12.00	SQ		7.86			12.00	S3	12.06	5.18	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment												
Total Solar Units									12.17	5.43	-5.3	-5.0
Sundance												
341.00 Structures and Improvements	2047	37-R3					2037	200-SC	30.70	28.41	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2047	37-R3					2037	200-SC	30.73	28.41	-5.0	-5.0
343.00 Prime Movers	2047	37-R3					2037	200-SC	30.72	28.41	-5.0	-5.0
344.00 Generators and Devices	2047	37-R3					2037	200-SC	29.25	28.41	-5.0	-5.0
345.00 Accessory Electric Equipment	2047	37-R3					2037	200-SC	30.73	28.41	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment	2047	37-R3					2037	200-SC	30.73	28.41	-5.0	-5.0
Total Sun Dance									30.72	28.41	-5.0	-5.0
West Phoenix												
341.00 Structures and Improvements									33.13	25.94	-5.3	
342.00 Fuel Holders, Products and Accessories									27.72	20.61	-5.0	
343.00 Prime Movers									33.20	27.79	-3.7	
344.00 Generators and Devices									29.85	24.56	-4.7	
345.00 Accessory Electric Equipment									29.10	22.78	-4.9	
346.00 Miscellaneous Power Plant Equipment									29.54	17.41	-5.3	
Total West Phoenix									30.89	25.23	-4.4	-5.0
West Phoenix CC Units 1-3												
341.00 Structures and Improvements	2031	80-S1		25.21	-5.0	-5.0	2028	200-SC	24.76	19.97	-4.9	-5.0
342.00 Fuel Holders, Products and Accessories	2031	70-S1		25.65	-5.0	-5.0	2028	200-SC	26.40	19.97	-5.0	-5.0
343.00 Prime Movers												
344.00 Generators and Devices	2031	37-R3		23.95	-2.0	-2.0	2028	200-SC	25.85	19.97	-4.2	-5.0
345.00 Accessory Electric Equipment	2031	50-S2		24.59			2028	200-SC	26.26	19.97	-4.8	-5.0
346.00 Miscellaneous Power Plant Equipment	2031	70-L1		24.26			2028	200-SC	32.86	19.96	-5.4	-5.0
Total West Phoenix CC Units 1-3									26.07	19.97	-4.4	-5.0

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
West Phoenix CC Unit 4												
341.00 Structures and Improvements	2056	80-S1		47.72	-5.0	-5.0	2036	200-SC	32.84	27.47	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2056	70-S1		46.34	-5.0	-5.0	2036	200-SC	33.52	27.47	-5.0	-5.0
343.00 Prime Movers	2056	70-L1.5		45.03	-2.0	-2.0	2036	200-SC	33.52	27.47	-5.0	-5.0
344.00 Generators and Devices	2056	37-R3		33.60	-2.0	-2.0	2036	200-SC	33.01	27.47	-5.2	-5.0
345.00 Accessory Electric Equipment	2056	70-S1		47.20	-5.0	-5.0	2036	200-SC	30.76	27.48	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment	2056	70-S1		46.63	-5.0	-5.0	2036	200-SC	31.27	27.47	-5.0	-5.0
Total West Phoenix CC Unit 4									33.38	27.47	-5.0	-5.0
West Phoenix CC Unit 5												
341.00 Structures and Improvements							2038	200-SC	33.49	29.32	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers							2038	200-SC	33.06	29.32	-3.1	-5.0
344.00 Generators and Devices							2038	200-SC	33.48	29.32	-5.0	-5.0
345.00 Accessory Electric Equipment							2038	200-SC	33.52	29.32	-5.0	-5.0
346.00 Miscellaneous Power Plant Equipment							2038	200-SC	31.63	29.33	-5.0	-5.0
Total West Phoenix CC Unit 5									33.31	29.32	-4.1	-5.0
West Phoenix CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		12.12	-5.0	-5.0	2020	200-SC	39.03	12.29	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		12.03	-5.0	-5.0	2020	200-SC	36.53	12.29	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		11.86			2020	200-SC	32.86	12.29	-4.8	-5.0
344.00 Generators and Devices	2017	37-R3		10.75			2020	200-SC	28.71	12.30	-5.0	-5.0
345.00 Accessory Electric Equipment	2017	50-S2		11.27			2020	200-SC	33.95	12.29	-5.4	-5.0
346.00 Miscellaneous Power Plant Equipment	2017	70-L1		12.02			2020	200-SC	23.33	12.30	-5.0	-5.0
Total West Phoenix CT Units 1-2									31.39	12.29	-4.9	-5.0

ARIZONA PUBLIC SERVICE COMPANY

Statement H

Present and Proposed Parameters
Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2007)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
West Phoenix Common												
341.00 Structures and Improvements	2017	80-S1		25.21	-5.0	-5.0	2031	200-SC	42.59	22.77	-6.5	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1										
343.00 Prime Movers	2017	70-L1.5										
344.00 Generators and Devices	2017	37-R3										
345.00 Accessory Electric Equipment	2017	50-S2										
346.00 Miscellaneous Power Plant Equipment	2017	70-L1										
Total West Phoenix Common									42.59	22.77	-6.5	-5.0
Yucca CT Units 1-4												
341.00 Structures and Improvements	2016	80-S1		11.35	-5.0	-5.0	2020	200-SC	21.94	12.30	-4.9	-5.0
342.00 Fuel Holders, Products and Accessories	2016	70-S1		11.00	-5.0	-5.0	2020	200-SC	41.81	12.29	-4.9	-5.0
343.00 Prime Movers	2016	70-L1.5		10.81			2020	200-SC	45.24	12.29	-5.0	-5.0
344.00 Generators and Devices	2016	37-R3		9.09			2020	200-SC	26.33	12.30	-4.9	-5.0
345.00 Accessory Electric Equipment	2016	50-S2		10.37			2020	200-SC	27.75	12.30	-5.2	-5.0
346.00 Miscellaneous Power Plant Equipment	2016	70-L1		10.90			2020	200-SC	27.71	12.30	-5.0	-5.0
Total Yucca CT Units 1-4									33.46	12.30	-5.0	-5.0

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the APS depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 367.00 – Underground Conductors and Devices. Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the APS study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. A weighted–average remaining–life is the sum of Column H divided by the sum of Column I. A weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column C) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged data is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–

of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant
Account: 367.00 UG Conductors and Devices

Dispersion: 33 - L1
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2007 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2007	0.5	116,426,148	33.00	32.53	0.9858	1.0000	114,773,441	3,528,219
2006	1.5	123,400,155	32.99	31.60	0.9580	1.0000	118,216,620	3,740,496
2005	2.5	93,726,306	32.99	30.70	0.9306	1.0000	87,224,649	2,841,054
2004	3.5	68,291,810	32.96	29.82	0.9048	1.0000	61,793,214	2,071,897
2003	4.5	59,306,495	32.97	28.98	0.8788	1.0000	52,117,366	1,798,634
2002	5.5	61,253,392	32.95	28.16	0.8546	1.0000	52,346,499	1,858,971
2001	6.5	72,078,892	32.98	27.37	0.8300	1.0000	59,826,240	2,185,473
2000	7.5	61,857,973	32.90	26.62	0.8092	1.0000	50,054,726	1,879,992
1999	8.5	55,167,382	32.94	25.91	0.7866	1.0000	43,392,919	1,674,702
1998	9.5	66,063,401	33.08	25.23	0.7628	1.0000	50,396,429	1,997,230
1997	10.5	44,613,284	33.09	24.59	0.7431	1.0000	33,154,176	1,348,184
1996	11.5	43,613,611	33.05	23.99	0.7257	1.0000	31,650,294	1,319,536
1995	12.5	32,483,683	32.02	23.41	0.7312	1.0000	23,752,640	1,014,427
1994	13.5	28,065,020	33.10	22.88	0.6911	1.0000	19,396,357	847,845
1993	14.5	30,052,611	33.09	22.37	0.6760	1.0000	20,316,858	908,174
1992	15.5	40,070,646	33.25	21.89	0.6584	1.0000	26,382,600	1,205,034
1991	16.5	24,984,962	33.27	21.44	0.6444	1.0000	16,100,448	750,884
1990	17.5	43,374,816	33.05	21.01	0.6357	1.0000	27,573,306	1,312,217
1989	18.5	34,765,939	32.76	20.60	0.6289	1.0000	21,863,397	1,061,246
1988	19.5	24,574,449	31.94	20.20	0.6326	1.0000	15,545,214	769,412
1987	20.5	17,365,190	31.36	19.81	0.6319	1.0000	10,972,457	553,748
1986	21.5	11,301,497	31.00	19.43	0.6269	1.0000	7,084,772	364,588
1985	22.5	14,456,955	31.83	19.06	0.5987	1.0000	8,655,949	454,233
1984	23.5	9,047,071	31.97	18.69	0.5844	1.0000	5,287,483	282,960
1983	24.5	5,261,625	32.05	18.32	0.5717	1.0000	3,007,827	164,161
1982	25.5	5,164,451	32.23	17.96	0.5575	1.0000	2,879,011	160,261
1981	26.5	7,778,184	32.11	17.61	0.5485	1.0000	4,266,621	242,250
1980	27.5	5,291,653	31.78	17.27	0.5433	1.0000	2,875,185	166,522
1979	28.5	2,740,520	30.74	16.93	0.5506	1.0000	1,508,819	89,146
1978	29.5	3,177,590	31.72	16.59	0.5230	1.0000	1,661,745	100,167
1977	30.5	1,976,152	31.44	16.26	0.5171	1.0000	1,021,851	62,846
1976	31.5	1,623,800	32.33	15.93	0.4929	1.0000	800,375	50,229
1975	32.5	2,385,467	32.11	15.61	0.4863	1.0000	1,160,041	74,292
1974	33.5	1,171,887	31.45	15.30	0.4865	1.0000	570,132	37,265
1973	34.5	1,244,942	32.71	14.99	0.4582	1.0000	570,469	38,059
1972	35.5	1,262,197	31.26	14.68	0.4697	1.0000	592,849	40,376
1971	36.5	699,144	28.78	14.38	0.4997	1.0000	349,353	24,291

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant
Account: 367.00 UG Conductors and Devices

Dispersion: 33 - L1
Procedure: Vintage Group

Generation Arrangement

	December 31, 2007							
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1970	37.5	4,550,624	37.63	14.09	0.3743	1.0000	1,703,474	120,938
1969	38.5	956,431	34.67	13.79	0.3978	1.0000	380,478	27,585
1968	39.5	2,040,953	38.62	13.50	0.3497	1.0000	713,686	52,847
1967	40.5	2,838,627	41.55	13.22	0.3182	1.0000	903,271	68,321
1966	41.5	840,169	39.77	12.94	0.3254	1.0000	273,388	21,126
1965	42.5	1,617,699	41.72	12.66	0.3036	1.0000	491,087	38,776
1964	43.5	1,296,261	40.10	12.39	0.3090	1.0000	400,604	32,327
1963	44.5	309,885	39.48	12.12	0.3071	1.0000	95,173	7,850
1962	45.5	1,157	29.13	11.86	0.4071	1.0000	471	40
1961	46.5	2,568,582	43.07	11.60	0.2693	1.0000	691,654	59,640
1960	47.5	49,763	37.37	11.34	0.3035	1.0000	15,101	1,332
1958	49.5	44,923	40.72	10.83	0.2661	1.0000	11,952	1,103
1956	51.5	1,584,614	47.10	10.34	0.2195	1.0000	347,888	33,644
1955	52.5	4,586	34.62	10.10	0.2917	1.0000	1,338	132
Total	9.3	$1,234,823,572	32.94	26.28	0.7978	1.0000	$985,171,899	$37,484,681

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2007	Derived Additions	1971 Opening Balance	Experience to 12/31/2007 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2007	0.5	116,850,070		116,426,148	0.9964	0.4982
2006	1.5	125,020,866		123,400,155	0.9870	1.4879
2005	2.5	94,986,198		93,726,306	0.9867	2.4827
2004	3.5	69,737,296		68,291,810	0.9793	3.4454
2003	4.5	60,443,418		59,306,495	0.9812	4.4446
2002	5.5	62,949,403		61,253,392	0.9731	5.4031
2001	6.5	73,960,504		72,078,892	0.9746	6.4083
2000	7.5	64,700,531		61,857,973	0.9561	7.2970
1999	8.5	57,677,987		55,167,382	0.9565	8.2918
1998	9.5	68,055,205		66,063,401	0.9707	9.3731
1997	10.5	46,200,367		44,613,284	0.9656	10.3197
1996	11.5	46,164,714		43,613,611	0.9447	11.1990
1995	12.5	39,234,587		32,483,683	0.8279	11.0714
1994	13.5	30,523,211		28,065,020	0.9195	13.0372
1993	14.5	32,816,271		30,052,611	0.9158	13.8944
1992	15.5	44,554,268		40,070,646	0.8994	14.9040
1991	16.5	28,805,479		24,984,962	0.8674	15.7530
1990	17.5	52,669,995		43,374,816	0.8235	16.3398
1989	18.5	44,412,568		34,765,939	0.7828	16.8291
1988	19.5	40,845,503		24,574,449	0.6016	16.7708
1987	20.5	30,915,267		17,365,190	0.5617	16.9304
1986	21.5	21,795,510		11,301,497	0.5185	17.2859
1985	22.5	24,788,467		14,456,955	0.5832	18.8095
1984	23.5	17,735,429		9,047,071	0.5101	19.6272
1983	24.5	8,745,998		5,261,625	0.6016	20.3553
1982	25.5	9,391,177		5,164,451	0.5499	21.1562
1981	26.5	13,919,665		7,778,184	0.5588	21.6442
1980	27.5	10,300,220		5,291,653	0.5137	21.8969
1979	28.5	6,639,562		2,740,520	0.4128	21.4228
1978	29.5	6,975,304		3,177,590	0.4555	22.9437
1977	30.5	4,439,942		1,976,152	0.4451	23.1837
1976	31.5	3,277,472		1,623,800	0.4954	24.5649
1975	32.5	5,492,569		2,385,467	0.4343	24.8231
1974	33.5	2,968,551		1,171,887	0.3948	24.6178
1973	34.5	2,820,655		1,244,942	0.4414	26.3176
1972	35.5	3,877,931		1,262,197	0.3255	25.2848
1971	36.5	2,578,611		699,144	0.2711	23.2034
1970	37.5		7,169,451	4,550,624	0.6347	32.4274

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2007	Derived Additions	1971 Opening Balance	Experience to 12/31/2007 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1969	38.5		1,968,869	956,431	0.4858	29.8317
1968	39.5		3,244,938	2,040,953	0.6290	34.1216
1967	40.5		3,838,902	2,838,627	0.7394	37.3743
1966	41.5		1,382,454	840,169	0.6077	35.9026
1965	42.5		2,643,892	1,617,699	0.6119	38.1429
1964	43.5		3,507,479	1,296,261	0.3696	36.7965
1963	44.5		1,017,190	309,885	0.3046	36.4323
1962	45.5		128,232	1,157	0.0090	26.3288
1961	46.5		6,995,427	2,568,582	0.3672	40.4976
1960	47.5		264,023	49,763	0.1885	35.0105
1959	48.5		93,968		0.0000	30.4671
1958	49.5		190,533	44,923	0.2358	38.7507
1957	50.5		67,204		0.0000	28.9379
1956	51.5		4,023,015	1,584,614	0.3939	45.4718
1955	52.5		122,718	4,586	0.0374	33.1466
1954	53.5		19,062		0.0000	31.2236
1953	54.5		15,400		0.0000	34.1003
1952	55.5		14,699		0.0000	33.4659
1951	56.5		4,289		0.0000	35.6181
1950	57.5		10,233		0.0000	44.0000
1946	61.5		8,447		0.0000	48.0000
1940	67.5		4,926		0.0000	42.7389
Total		$1,377,270,769	$36,735,351	$1,234,823,572	0.8733	

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1971	11,234,859	5,227,485			16,462,344
1972	16,462,344	5,626,788	167,216		21,921,916
1973	21,921,916	5,899,426	110,107		27,711,235
1974	27,711,235	6,605,495	72,619		34,244,111
1975	34,244,111	4,188,877	143,093		38,289,895
1976	38,289,895	4,904,543	119,194	196	43,075,440
1977	43,075,440	7,682,950	62,687	135	50,695,839
1978	50,695,839	6,255,514	144,347	223	56,807,229
1979	56,807,229	12,165,882	180,100	338	68,793,348
1980	68,793,348	11,925,816	261,221	6,573	80,464,517
1981	80,464,517	13,706,676	311,535	(182)	93,859,475
1982	93,859,475	12,677,752	280,423		106,256,805
1983	106,256,805	12,220,047	167,539	27	118,309,340
1984	118,309,340	24,564,892	620,234	(711,901)	141,542,097
1985	141,542,097	28,119,927	588,413	100,773	169,174,384
1986	169,174,384	33,086,796	776,947	(819,083)	200,665,150
1987	200,665,150	40,442,295	1,411,693	11,977	239,707,730
1988	239,707,730	44,562,290	1,298,863	(102,165)	282,868,992
1989	282,868,992	39,930,190	1,822,189	1,230,377	322,207,369
1990	322,207,369	48,232,643	2,081,398	(242,515)	368,116,099
1991	368,116,099	26,258,331	6,505,011	(35,194)	387,834,225
1992	387,834,225	43,961,641	7,676,820	(25,026,623)	399,092,424
1993	399,092,424	32,825,279	12,346,537	(323,901)	419,247,265
1994	419,247,265	30,533,944	6,133,313	385,837	444,033,733
1995	444,033,733	39,423,523	5,497,824		477,959,432
1996	477,959,432	46,015,566	2,560,192		521,414,806
1997	521,414,806	45,962,909	8,905,235	(37,625)	558,434,855
1998	558,434,855	67,536,428	21,756,216		604,215,067
1999	604,215,067	57,369,075	9,569,466		652,014,675
2000	652,014,675	63,360,845	10,611,085		704,764,435
2001	704,764,435	51,081,906	10,079,147		745,767,195
2002	745,767,195	69,400,154	13,144,993		802,022,355
2003	802,022,355	60,001,037	12,088,891		849,934,501
2004	849,934,501	74,271,162	15,315,290		908,890,373
2005	908,890,373	91,985,491	7,426,563	379,484	993,828,785
2006	993,828,785	123,918,259	8,664,638	429	1,109,082,836
2007	1,109,082,836	134,150,439	10,281,509	1,871,806	1,234,823,572

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1971	11,234,864	5,227,485			16,462,349
1972	16,462,349	6,221,813	167,216		22,516,945
1973	22,516,945	6,947,551	109,802		29,354,694
1974	29,354,694	5,440,303	71,744		34,723,254
1975	34,723,254	3,856,115	143,398		38,435,971
1976	38,435,971	4,856,897	108,092	196	43,184,972
1977	43,184,972	5,547,135	73,789	135	48,658,453
1978	48,658,453	9,535,217	144,905	223	58,048,988
1979	58,048,988	11,431,460	180,100	338	69,300,686
1980	69,300,686	12,364,994	261,538	6,573	81,410,715
1981	81,410,715	13,176,164	311,535	(182)	94,275,162
1982	94,275,162	12,706,413	280,423		106,701,152
1983	106,701,152	13,043,237	165,751	27	119,578,665
1984	119,578,665	21,961,759	617,304	(711,901)	140,211,219
1985	140,211,219	24,615,706	591,343	100,773	164,336,355
1986	164,336,355	33,743,754	773,965	(819,083)	196,487,061
1987	196,487,061	32,879,617	1,408,643	11,977	227,970,013
1988	227,970,013	43,231,460	1,217,615	(102,165)	269,881,693
1989	269,881,693	49,800,109	1,833,911	1,230,377	319,078,267
1990	319,078,267	46,930,342	2,081,042	(242,515)	363,685,053
1991	363,685,053	36,860,085	6,580,659	(35,194)	393,929,285
1992	393,929,285	38,616,944	7,675,544	(25,026,623)	399,844,063
1993	399,844,063	32,819,107	12,345,547	(323,901)	419,993,722
1994	419,993,722	30,531,422	6,132,492	385,837	444,778,489
1995	444,778,489	39,241,705	5,497,343		478,522,851
1996	478,522,851	46,165,350	2,559,267		522,128,934
1997	522,128,934	46,200,367	8,902,760	(37,625)	559,388,916
1998	559,388,916	67,699,385	21,754,729		605,333,572
1999	605,333,572	57,612,159	9,560,988		653,384,743
2000	653,384,743	64,539,590	10,610,781		707,313,553
2001	707,313,553	73,621,566	10,078,436		770,856,683
2002	770,856,683	62,688,687	13,144,764		820,400,606
2003	820,400,606	59,953,456	12,111,789		868,242,273
2004	868,242,273	69,632,987	15,353,546		922,521,713
2005	922,521,713	94,613,649	7,750,593	379,484	1,009,764,253
2006	1,009,764,253	124,918,208	8,299,685	429	1,126,383,205
2007	1,126,383,205	116,850,070	10,281,509	1,871,806	1,234,823,572

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2007
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-1975	66.1	51.2	L0.5	2.56	47.3	L1	2.86	36.8	R2	4.41
1972-1976	67.5	55.1	L0.5	2.59	51.6	L1	2.71	41.2	R1.5	3.25
1973-1977	82.2	75.7	L0.5	2.07	140.3	SC *	1.46	49.8	R2	2.41
1974-1978	81.4	73.3	L0.5	1.91	136.9	SC *	1.16	51.8	R2	2.10
1975-1979	71.5	59.4	L1	1.58	53.0	L1.5	2.34	113.9	O3 *	1.84
1976-1980	66.2	55.6	L1	1.94	45.2	S0.5	4.34	138.2	SC *	2.05
1977-1981	50.2	48.3	L1 *	2.61	37.8	S1	5.92	104.1	O4 *	2.99
1978-1982	44.7	46.4	L1.5 *	2.84	36.1	S1	7.07	102.9	O4 *	3.20
1979-1983	48.1	49.4	L1.5 *	2.64	38.1	S1	7.44	117.2	O3 *	3.50
1980-1984	27.2	45.8	L1.5 *	7.30	33.8	S1.5	6.44	61.9	O4 *	3.19
1981-1985	23.0	45.7	L1.5 *	8.23	33.5	S1.5	6.96	43.5	L2 *	4.33
1982-1986	21.1	46.3	L1.5 *	8.78	34.0	S1.5	6.52	34.7	S1.5	5.52
1983-1987	13.3	45.2	L1 *	12.03	32.6	S1.5	5.09	32.5	S1.5	5.23
1984-1988	13.1	44.8	L1	10.54	33.2	S1.5	5.13	32.8	S1.5	5.80
1985-1989	16.8	44.2	L1	7.57	35.0	S1	4.16	34.0	R2	5.58
1986-1990	5.1	41.5	L1	9.37	33.5	S1	2.75	32.5	R2	4.25
1987-1991	4.6	43.9	L0	10.73	34.8	R1	3.38	31.1	R2	7.25
1988-1992	0.4	34.8	L0.5	13.11	92.6	O4 *	20.23	103.3	O4 *	22.87
1989-1993	0.8	27.3	L0.5	6.54	80.0	O4 *	16.27	78.5	O4 *	15.82
1990-1994	0.0	27.3	L0.5	8.31	76.2	O4 *	16.38	73.0	O4 *	15.33
1991-1995	0.0	27.8	L0.5	9.71	74.1	O4 *	15.87	69.7	O4 *	14.31
1992-1996	0.0	30.3	L0.5	12.58	79.5	O4 *	16.75	74.0	O4 *	14.89
1993-1997	0.0	29.6	L1	8.89	54.8	O4 *	10.36	64.9	O4 *	12.14
1994-1998	0.0	25.7	L1.5 *	4.13	26.0	S0.5	3.27	26.7	R1.5	3.42
1995-1999	0.0	26.0	L1.5 *	4.67	26.0	S0.5	3.39	26.6	R1.5	2.58
1996-2000	5.5	26.2	L1.5 *	5.41	26.0	S0.5	4.34	26.5	R1	3.04
1997-2001	5.8	25.9	L1.5 *	5.15	25.6	S0.5	4.61	25.8	S0	3.66
1998-2002	10.9	26.5	L1 *	4.23	26.4	L1	4.30	26.4	L1	4.25
1999-2003	46.1	33.4	L0.5	10.39	95.5	O4 *	3.84	90.9	O4 *	5.31
2000-2004	34.3	32.2	L0.5	9.16	86.7	O4 *	3.35	81.3	O4 *	4.91
2001-2005	25.3	34.2	L0.5	8.18	89.2	O4 *	3.80	85.7	O4 *	5.07
2002-2006	42.5	36.6	L1	8.30	94.2	O4 *	3.15	91.5	O4 *	4.71
2003-2007	44.2	39.6	L1	7.12	94.5	O4 *	3.08	95.6	O4 *	4.62

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2007
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-2007	0.0	32.5	L1	4.53	40.3	O2 *	3.33	66.3	O4 *	4.05
1973-2007	0.0	32.5	L1	4.53	40.4	O2 *	3.33	66.3	O4 *	4.05
1975-2007	0.0	32.5	L1	4.53	40.4	O2 *	3.33	66.3	O4 *	4.05
1977-2007	0.0	32.4	L1	4.52	40.5	O2 *	3.33	66.2	O4 *	4.04
1979-2007	0.0	32.4	L1	4.52	40.6	O2 *	3.33	66.2	O4 *	4.04
1981-2007	0.0	32.4	L1	4.52	40.8	O2 *	3.32	66.1	O4 *	4.03
1983-2007	0.0	32.3	L1	4.52	41.1	O3 *	3.31	65.9	O4 *	4.02
1985-2007	0.0	32.2	L1	4.53	41.6	O3 *	3.30	65.7	O4 *	4.00
1987-2007	0.0	32.1	L1	4.55	42.4	O3 *	3.29	65.5	O4 *	3.99
1989-2007	0.0	32.0	L1	4.60	43.6	O3 *	3.29	65.1	O4 *	3.99
1991-2007	0.0	31.8	L1	4.61	44.6	O3 *	3.28	64.8	O4 *	3.98
1993-2007	0.0	31.9	L1	4.62	43.7	O3 *	3.28	64.5	O4 *	3.99
1995-2007	0.0	32.7	L1	4.04	35.5	L0.5 *	3.27	63.5	O4 *	3.90
1997-2007	22.3	32.1	L1	3.07	33.0	L1 *	2.44	58.6	O4 *	2.89
1999-2007	44.5	36.9	L0.5	9.36	98.2	O4 *	3.24	95.6	O4 *	4.56
2001-2007	43.4	37.6	L0.5	8.42	96.5	O4 *	3.13	94.2	O4 *	4.71
2003-2007	44.2	39.6	L1	7.12	94.5	O4 *	3.08	95.6	O4 *	4.62
2005-2007	52.4	46.1	L1	5.97	94.9	O4 *	3.54	108.9	O4 *	4.86
2007-2007	52.5	43.5	L1	7.42	88.0	O4 *	4.78	99.6	O4 *	6.68

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2007
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1971-1972	66.4	44.0	L0.5	3.58	32.1	S1	8.15	29.7	R2	9.75
1971-1974	71.2	55.1	L0.5	3.05	42.9	S0.5	4.56	36.9	R2	5.73
1971-1976	68.3	57.6	L0.5	2.48	55.0	L1	2.50	40.7	R2	3.14
1971-1978	67.7	69.6	L0.5	3.35	54.4	S0.5	2.42	80.6	O3 *	2.59
1971-1980	53.1	56.4	L1	4.88	43.9	S0.5	1.73	115.4	O3 *	3.16
1971-1982	37.5	50.4	L1	7.56	37.6	S1	1.70	78.8	O4 *	2.58
1971-1984	25.5	48.9	L1 *	9.27	35.4	S1.5	3.22	41.3	L2 *	1.89
1971-1986	16.7	47.8	L1 *	11.10	34.9	S1.5	2.85	35.2	S1.5	2.59
1971-1988	10.0	47.0	L1	13.18	34.5	S1.5	2.06	34.3	S1.5	2.21
1971-1990	2.5	43.5	L1 *	13.65	33.8	S1	1.93	33.5	S1.5	1.49
1971-1992	0.9	38.2	L0.5	13.83	39.2	L0.5	14.45	107.6	O4 *	21.75
1971-1994	0.0	31.5	L1	8.25	87.9	O4 *	17.79	92.7	O4 *	19.24
1971-1996	0.0	33.8	L1	10.01	96.2	O4 *	19.02	94.6	O4 *	18.57
1971-1998	0.0	27.4	L1.5 *	4.22	26.9	S0.5	3.52	27.2	S0.5	3.11
1971-2000	0.0	28.4	L1 *	3.81	27.9	L1.5	3.42	27.9	S0	2.92
1971-2002	0.0	29.0	L1	4.16	29.2	L1	4.32	30.8	L1 *	4.54
1971-2004	0.0	29.6	L1	3.48	31.7	L0.5 *	3.52	53.9	O4 *	5.20
1971-2006	0.0	31.6	L1	4.21	37.1	L0.5 *	3.15	62.3	O4 *	3.83
1971-2007	0.0	32.5	L1	4.53	40.3	O2 *	3.33	66.3	O4 *	4.05

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None

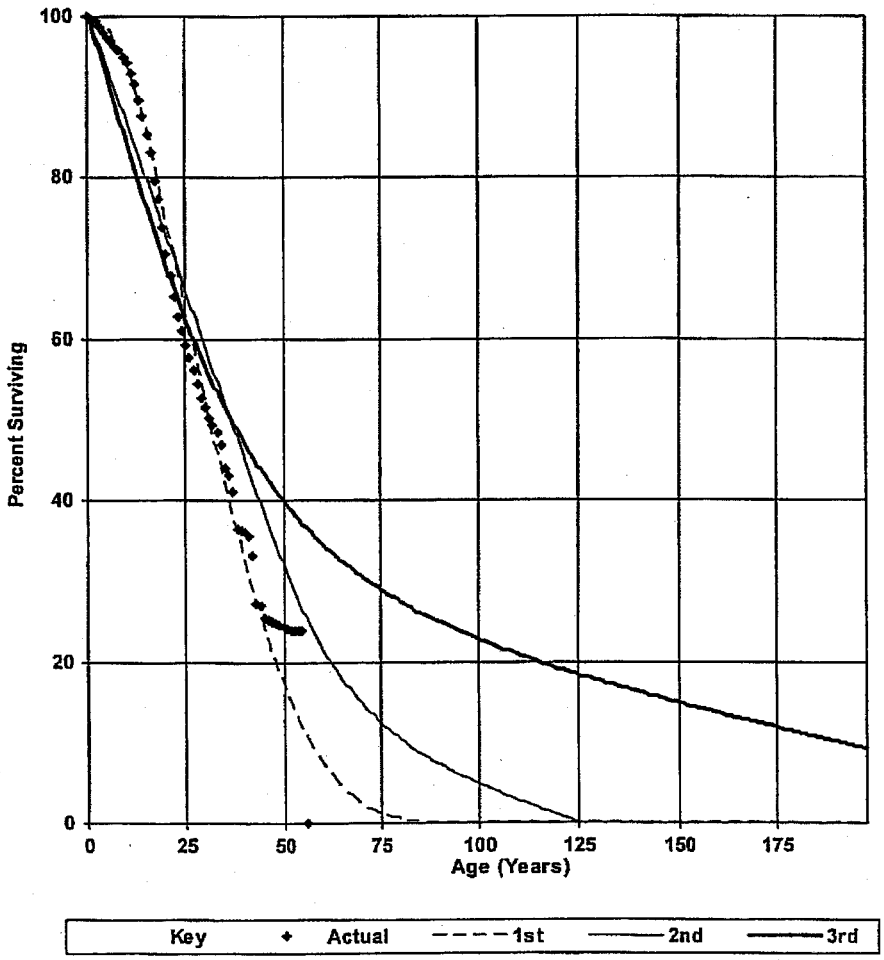
Placement Band: 1940-2007 Observation Band: 1971-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 32.5-L1 2nd: 40.3-O2 3rd: 66.3-O4



ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None

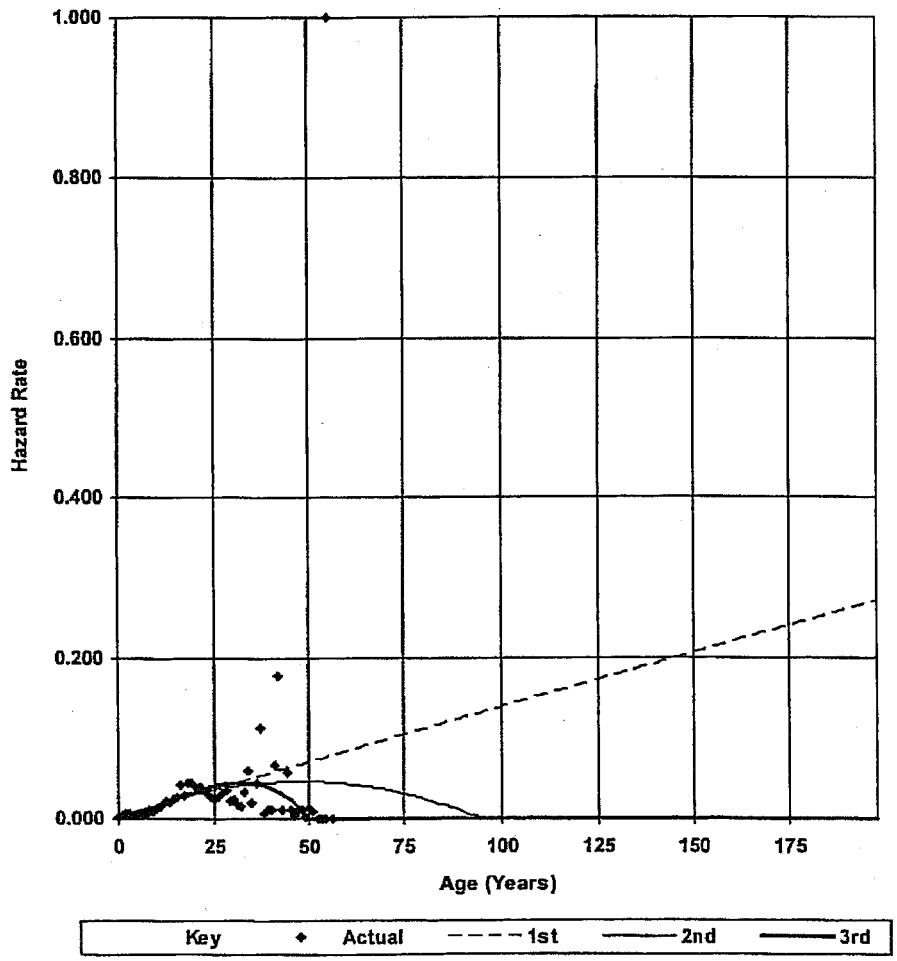
Placement Band: 1940-2007 Observation Band: 1971-2007

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 32.5-L1 2nd: 40.3-O2 3rd: 66.3-O4



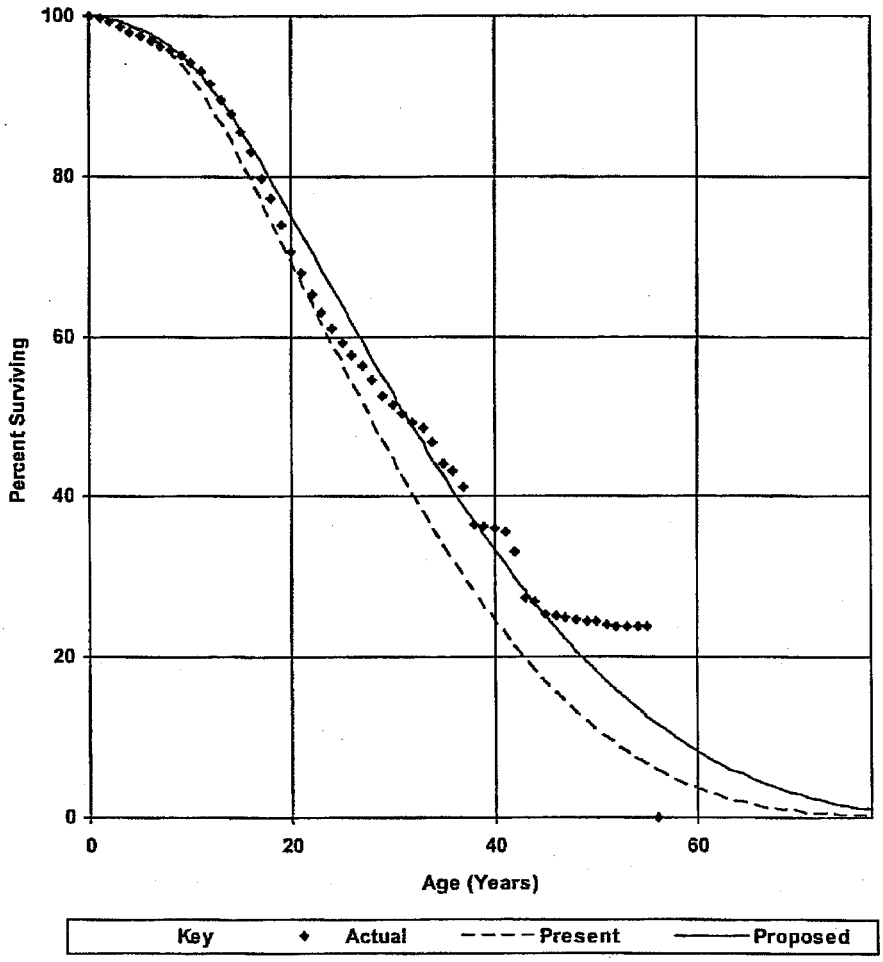
ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

T-Cut: None
Placement Band: 1940-2007
Observation Band: 1971-2007

Present and Proposed Projection Life Curves Present: 29.0-L1 Proposed: 33.0-L1



ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1993	12,346,537	2,524,434	20.4		1,610,244	13.0		914,190	7.4	
1994	6,133,313	1,148,835	18.7		909,409	14.8		239,426	3.9	
1995	5,497,824	1,113,693	20.3		616,784	11.2		496,909	9.0	
1996	2,560,192	265,961	10.4		270,617	10.6		(4,655)	-0.2	
1997	8,905,235	1,174,025	13.2	17.6	597,293	6.7	11.3	576,731	6.5	6.3
1998	21,756,216		0.0	8.3	4,596	0.0	5.3	(4,596)	0.0	2.9
1999	9,569,466		0.0	5.3	13,462	0.1	3.1	(13,462)	-0.1	2.2
2000	10,611,085	2,917,118	27.5	8.2	851,477	8.0	3.3	2,065,640	19.5	4.9
2001	10,079,147	1,973,691	19.6	10.0	1,993,829	19.8	5.7	(20,138)	-0.2	4.3
2002	13,144,993	1,533,592	11.7	9.9	2,379,742	18.1	8.0	(846,150)	-6.4	1.8
2003	12,088,891	1,208,607	10.0	13.8	2,121,011	17.5	13.3	(912,404)	-7.5	0.5
2004	15,315,290	1,306,856	8.5	14.6	1,971,252	12.9	15.2	(664,396)	-4.3	-0.6
2005	7,426,563	1,536,983	20.7	13.0	3,342,225	45.0	20.3	(1,805,242)	-24.3	-7.3
2006	8,664,638	4,972,381	57.4	18.6	2,695,724	31.1	22.1	2,276,657	26.3	-3.4
2007	10,281,509	3,672,708	35.7	23.6	3,782,266	36.8	25.9	(109,557)	-1.1	-2.3
Total	154,380,898	25,348,884	16.4		23,159,931	15.0		2,188,953	1.4	

ARIZONA PUBLIC SERVICE COMPANY

Distribution Plant

Account: 367.00 UG Conductors and Devices

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1993	12,345,547	2,524,434	20.4		1,610,244	13.0		914,190	7.4	
1994	6,132,492	1,148,835	18.7		909,409	14.8		239,426	3.9	
1995	5,497,343	1,113,693	20.3		616,784	11.2		496,909	9.0	
1996	2,559,267	265,961	10.4		270,617	10.6		(4,655)	-0.2	
1997	8,902,760	1,174,025	13.2	17.6	597,293	6.7	11.3	576,731	6.5	6.3
1998	21,754,729		0.0	8.3	4,596	0.0	5.3	(4,596)	0.0	2.9
1999	9,560,988		0.0	5.3	13,462	0.1	3.1	(13,462)	-0.1	2.2
2000	10,610,781	2,917,118	27.5	8.2	851,477	8.0	3.3	2,065,640	19.5	4.9
2001	10,078,436	1,973,691	19.6	10.0	1,993,829	19.8	5.7	(20,138)	-0.2	4.3
2002	13,144,764	1,533,592	11.7	9.9	2,379,742	18.1	8.0	(846,150)	-6.4	1.8
2003	12,111,789	1,208,607	10.0	13.8	2,121,011	17.5	13.3	(912,404)	-7.5	0.5
2004	15,353,546	1,306,856	8.5	14.6	1,971,252	12.8	15.2	(664,396)	-4.3	-0.6
2005	7,750,593	1,536,983	19.8	12.9	3,342,225	43.1	20.2	(1,805,242)	-23.3	-7.3
2006	8,299,685	4,972,381	59.9	18.6	2,695,724	32.5	22.1	2,276,657	27.4	-3.4
2007	10,281,509	3,672,708	35.7	23.6	3,782,266	36.8	25.9	(109,557)	-1.1	-2.3
Total	154,384,229	25,348,884	16.4		23,159,931	15.0		2,188,953	1.4	

Patrick Dinkel

DIRECT TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY 1

II. BACKGROUND: THE YUMA ACQUISITION DOCKET 2

III. USED AND USEFUL: APS'S NEED FOR YUMA ASSETS 4

IV. THE DECISION TO PURSUE THE DIRECT BUILD ALTERNATIVE WAS REASONABLE AND PRUDENT 5

DIRECT TESTIMONY OF PATRICK DINKEL
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E- 01345A-08-0172)

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Patrick Dinkel. I am the Director of Resource Acquisitions and Renewable Energy for Arizona Public Service Company ("APS" or "Company"). I led the APS team that was responsible for conducting the APS 2005 Requests for Proposals ("RFP") for Long-Term Capacity Supply in Yuma ("Yuma RFP"), evaluating the resulting proposals, and selecting the preferred option that resulted in APS contracting with Wood Group Power Solutions, Inc. ("Wood Group") for the construction of the new peaking facilities at the Yucca Power Plant in Yuma, Arizona ("Yuma Assets").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors of Science degree from Marymount College and a Masters of Business Administration from Northern Arizona University. I joined APS in 1986. Before becoming Director of Corporate Planning and Renewable Energy in 2004, I was the Manager of Corporate Planning and the Manager of Business Unit Analysis and Reporting. Before that, I held various positions within APS and Pinnacle West Capital Corporation ("Pinnacle West"), primarily within the financial planning and budgeting areas.

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

A. APS is seeking to include the Yuma Assets in rate base. My testimony explains the Company's decision to construct these facilities through a "direct build"

approach, by contracting with an Engineering, Procurement and Construction ("EPC") contractor, as well as the need for these facilities in the Yuma area, making them "used and useful" when they are placed in service. APS witness Daniel Kearns will discuss the rate base and operating income pro formas for the Yuma Assets.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have. I testified in support of APS's requests to both acquire the Sundance Assets (Docket No. E-01345A-04-0407) and to include those assets in rate base in the Company's last general rate case (Docket No. E-01345A-05-0816). I also testified in support of APS's request for authorization to acquire the Yuma Assets in Docket No. E-01345A-06-0464 ("Yuma Acquisition Docket").

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony will demonstrate that:

- New generation resources are needed to meet the Company's continued load growth in the Yuma load pocket, which will make the Yuma Assets used and useful when they go into service during the summer of 2008.
- The Company's ultimate decision to pursue the direct build alternative and contract with the Wood Group to construct the Yuma Assets was prudent, because the Company determined that this was the most cost effective means of acquiring critical long-term peaking capacity.

II. BACKGROUND: THE YUMA ACQUISITION DOCKET

Q. WHAT WAS THE PURPOSE OF THE YUMA ACQUISITION DOCKET?

A. In Decision No. 67744 (April 7, 2005), the Commission adopted, with

modification, the provisions of a Settlement Agreement that limited the ability of the Company to "self-build" generation assets that would be placed into service prior to January 1, 2015 without Commission authorization. In that Decision, the Commission modified the Settlement Agreement's definition of self-build to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator. Accordingly, APS was required to obtain the approval of the Commission whether the Company directly contracts for EPC ("direct build") or enters into a contract for the acquisition with a third party, such as a developer. In the Yuma Acquisition Docket, the Company sought such authorization. My testimony in the Yuma Acquisition Docket addressed the Yuma RFP and the evaluation process that resulted in the request for authorization for APS to acquire the Yuma Assets.

Q. WHAT WAS THE OUTCOME OF THE YUMA ACQUISITION DOCKET?

A. In Decision No. 69400 (March 30, 2007), the Commission granted APS's request for authorization to purchase a new generation resource within the Company's Yuma load pocket, finding that the Company's application met the requirements of Decision No. 67744. The Commission, therefore, authorized APS to acquire the Yuma Assets pursuant to either an agreement with a developer or an agreement with an EPC contractor. The Commission held for a future APS rate case the determination of the prudence of the Yuma Assets.

Q. WHAT IS THE COMPANY SEEKING IN THIS DOCKET?

A. The Company is now requesting that the Commission find that its acquisition of the Yuma Assets was prudent, that those facilities will be used and useful when

they are placed into service during the summer of 2008, and that APS is authorized to place those assets in rate base in this proceeding.

III. USED AND USEFUL: APS'S NEED FOR YUMA ASSETS

Q. PLEASE DESCRIBE THE YUMA ASSETS.

A. The Yuma Assets consist of two natural gas-fired, simple cycle, peaking electric generating units located at the Yucca Power Plant in Yuma, Arizona. Each unit is a 48 MW General Electric LM6000-PC combustion turbine with inlet chilling. The combustion turbines are similar to the units that were installed at the APS Sundance Power Plant and use well-known technology with a solid operational and environmental track record.

Q. ARE THE YUMA ASSETS CURRENTLY IN SERVICE?

A. The Yuma Assets are still under construction. The project is on-schedule and the units are anticipated to be on-line by summer of 2008, which is well before the expected order in this rate case.

Q. WHY DOES APS BELIEVE THAT ADDITIONAL GENERATION IS NEEDED IN YUMA?

A. The customer load in Yuma is growing at a rapid rate, and Yuma is fast approaching the limits on the amount of power that can be supplied by the existing generation and transmission facilities. In the Yuma Acquisition Docket, the Company presented evidence that to serve the load growth in Yuma and maintain adequate reliability of service, additional generation resources are needed in Yuma by 2008. Because the need is specific to summer capacity, Yuma requires peaking resources rather than intermediate or base load resources. The Commission recognized this need in Decision No. 69400, where it was specifically stated that, "[d]ue to transmission constraints, a load pocket

currently exists in the Yuma area, and the need for generation resources in Yuma at this time is for peaking generation within a load pocket." (*See* Finding of Fact No. 3.)

Q. WHAT IS YOUR UNDERSTANDING OF THE REGULATORY CRITERIA FOR A PLANT TO BE CONSIDERED "USED AND USEFUL"?

A. My understanding of the criteria to be considered in determining if a plant is used and useful is fairly straight forward. If the plant is needed to serve customers, it is considered used and useful. The need for the Yuma Assets was established in the Yuma Acquisition Docket.

Q. ARE THE YUMA ASSETS USED AND USEFUL?

A. When the Yuma Assets are placed in service this summer, they will be fully committed to our customers. As such, those facilities will meet the used and useful test.

IV. THE DECISION TO PURSUE THE DIRECT BUILD ALTERNATIVE WAS REASONABLE AND PRUDENT.

Q. PLEASE EXPLAIN THE ISSUES RAISED IN THE YUMA ACQUISTION DOCKET THAT YOU ARE ADDRESSING IN THIS RATE CASE.

A. In the Yuma Acquisition Docket, the Company had filed an Application to request authority to self-build a peaking generation plant either through APS's direct build alternative or through a contract with a developer. Under either alternative, APS would own the facilities. The Company was compelled to make such an application because, as recognized by the Commission in Decision No. 69400, self-build was the preferred result over any purchased power agreement provided by the wholesale market in response to the Yuma RFP. (*See* Finding of Fact No. 16.) During the Yuma Acquisition hearing, evidence was

presented regarding the differences between the direct build alternative and the developer build alternative, and there was no dispute regarding the methodology used to make the comparison. However, at the time Decision No. 69400 was issued, neither APS's direct build alternative nor the developer build alternative proposals were complete, meaning cost estimates were not finalized, and thus the cost differential could not be known with certainty. (*See* Finding of Fact No. 22.) Since that time, both those proposals and the cost estimates have been finalized.

Q. HOW DID APS ELECT TO PROCEED WITH THE NEW YUMA RESOURCES?

A. The Commission authorized the Company to move forward with either ownership alternative – the developer build alternative or the EPC contractor. Subsequent to that Commission decision, the Company negotiated final terms and specifications, at which point, both alternatives were comparable from a technical and operational perspective. Both the developer proposal and the Wood Group proposal were based on the same technology – two GE LM 6000 units. Based on an analysis of these refreshed and final offers from the developer and from the EPC contractor, APS determined that the most economic approach was to enter into an agreement with the EPC contractor, Wood Group, for the construction of the new Yuma units.

Q. WAS THE DECISION TO PROCEED WITH THE EPC CONTRACTOR APPROPRIATE?

A. Yes. All of the economic analyses showed that entering into a contract with the Wood Group was the most economic alternative for meeting our customers' needs.

Q. WHAT WAS THE COST DIFFERENCE BETWEEN THE DIRECT BUILD PROPOSAL AND THE DEVELOPER PROPOSAL?

A. The direct build proposal was $4.6 million less than the cost of the developer proposal.

Q. DO YOU BELIEVE THAT THE DECISION TO PROCEED WITH THE DIRECT BUILD PROPOSAL WAS PRUDENT?

A. Yes. APS's decision to enter into an EPC agreement with the Wood Group for the Yuma Assets was the product of a fair and open procurement process and was based on sound economic principles. APS has a clearly defined need for the units in the Yuma load pocket starting in summer 2008, as shown by its resource plans. The technology proposed by both proposals was similar, and the direct build proposal was the most economic choice.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

David J. Rumolo

DIRECT TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

TABLE OF CONTENTS

I. Introduction 1

II. Summary 2

III. "SFR" Schedules 4

IV. Pro Forma Adjustments 8

V. Impact Fees 9

VI. Cost-Of-Service Study 15

VII. Transmission Costs 23

VIII. Schedule 3 24

IX. Conclusion 25

Statement of Qualifications ..... Appendix A

Schedule GJ ..... Attachment DJR-1

Schedule GE-1 ..... Attachment DJR-2

Schedule GE-2 ..... Attachment DJR-3

Schedule GE-3 ..... Attachment DJR-4

Standard Filing Requirements Index for Sponsorship ..... Attachment DJR-5

Monthly Bill Impact (Base Rates) ..... Attachment DJR-6

Lobbying Expenses Pro Forma Adjustment ..... Attachment DJR-7

SurePay/AutoPay Pro Forma Adjustment ..... Attachment DJR-8

Service Schedule 6 – Impact Fee ..... Attachment DJR-9

Adjustment Schedule TCA-1 ..... Attachment DJR-10

Service Schedule 3 (Redline version) ..... Attachment DJR-11

DIRECT TESTIMONY OF DAVID J. RUMOLO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Rumolo. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Arizona Public Service Company ("APS" or "Company") as Manager of Regulation and Pricing. I am responsible for the establishment and administration of APS tariffs and contract provisions that are under the jurisdiction of the Arizona Corporation Commission ("ACC" or "Commission"). I am also responsible for certain aspects of APS tariffs that fall within the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. My background and experience are set forth in Appendix A to this testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses several general areas. The first area of my testimony discusses the Standard Filing Requirements ("SFR") schedules, including Schedule A-1 that presents the overall increase in revenue requirements requested in this Application. Second, I discuss the pro forma adjustments that I am sponsoring. Third, I discuss hook-up or impact fees and propose a new service schedule that would allow APS to charge an Impact Fee to new customer sites that have never had APS electric service. Fourth, I discuss the cost-of-

service study prepared to functionalize, classify, and then allocate test year costs and revenues, first between wholesale and retail customers and then to the various classes of retail service. It is this cost allocation study that allows us to determine the rate of return produced by each class and subclass of customer, as well as the unit costs APS incurs to provide different services to each customer group. Next, I discuss the current transmission cost recovery mechanism and unbundled transmission rate schedule and propose enhancements to that mechanism. Finally, I discuss Service Schedule 3, the APS line extension policy, and propose some minor revisions that clarify the language that describes the costs recovered through that schedule.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. My testimony addresses certain Standard Filing Requirements exhibits including Schedule A-1 that demonstrates the $448,194,000 increase in revenue requirements that is sought by the Company. This amount includes a $264.3 million increase in non-fuel rates and a net increase to the fuel-related component of rates of $13.9 million. The $448.2 million base rate increase sought in this application includes $183.9 million of fuel and purchased power costs. However, the Company will recover $170.0 million of that amount under the normal operation of the Power Supply Adjuster ("PSA"). Therefore, taking into consideration the reclassification of PSA revenues to base fuel revenues, as called for in the Commission-approved PSA plan of administration, the Company's effective net revenue increase request is $278.2 million. This additional revenue will allow APS to earn a rate of return of 6.16% on a fair value rate base of $7,713,316,000 or 8.86% on an adjusted original cost rate

base of $5,359,964,000. The adjusted test year rate of return on original cost rate base is 3.79% and a mere 2.63% on fair value rate base.

The rates proposed by APS would result in a $15.49 monthly increase for a typical residential customer. The monthly total increase for a typical small general service customer is $93.43. Similarly, the monthly total increase for a typical industrial customer is $23,798. These typical increases include the effect of resetting the base fuel amount from 3.25 ¢/kWh to 3.88 ¢/kWh. Based on current expectations, the PSA Forward Component would be zero. The actual PSA Forward Component will depend on several factors including the timing of a final order in this rate case. If APS's proposed impact fee is adopted to recover much of the anticipated attrition, these increases could drop by as much as another 2%.

I sponsor two specific pro forma adjustments for: 1) the recovery of costs associated with a portion of APS's lobbying expenses; and 2) an income adjustment that accounts for the decreased revenue due to the Surepay/Autopay discounts ordered in Decision No. 69663 (June 28, 2007). I also discuss a new schedule, Service Schedule 6, that proposes a new hook-up fee to be collected from new customers. The proposed hook-up fee, designated the "Impact Fee" would generate additional revenue that could offset a portion of the $79.3 million attrition component of the $264.3 million increased non-fuel base rate revenue requirements. The Impact Fee would further the Commission's goal of making growth pay for itself and providing some level of rate moderation for existing customers by addressing a large component of the future attrition that will largely take place during the course of this proceeding. The proposed

impact fee is designed to recover $53 million of growth related costs. Because of volatility in the Arizona real estate market, the proposed Impact Fee is based on the average number of actual and forecast new meter sets over the five-year period ending in 2012. The five-year average includes a period of high growth, a soft real estate market period and a forecast recovery period.

My testimony describes the cost of service study used to support the Company's rate designs in the Company's application as well as the jurisdictional allocation of costs. I also describe a proposed change to Schedule TCA-1 that provides for collection of FERC regulated transmission costs through the Schedule rather than partially through base rates and partially through an adjustment mechanism. Finally, I sponsor minor revisions to the APS line extension policy, Service Schedule 3. These changes have no impact on the substance of the policy as ordered by the Commission in Decision No. 70185 (February 27, 2008), but merely add some clarifying language regarding the implementation of the Service Schedule.

III. "SFR" SCHEDULES

Q. ARE YOU SPONSORING ANY STANDARD FILING REQUIREMENTS ("SFR") SCHEDULES?

A. Yes. I am sponsoring SFR Schedules A-1, portions of B-1, B-2, C-1, C-2 and G. Although not specifically required by the SFR, I am also sponsoring some additional schedules that are attached to my testimony and designated as Schedule GJ (Attachment DJR-1), Schedule GE-1 (Attachment DJR-2), Schedule GE-2 (Attachment DJR-3), and Schedule GE-3 (Attachment DJR-4). I have also attached an SFR index that lists the APS witnesses responsible for preparation of the SFRs or elements of the SFRs (Attachment DJR-5)

Q. PLEASE DESCRIBE THE ELEMENTS OF THE SFRs THAT YOU ARE SPONSORING.

A. I am sponsoring portions of SFR Schedules A, B, C, and G. In doing so, I rely on input from numerous witnesses. Moreover, I am sponsoring the jurisdictional splits, *i.e.* the allocation of rate base and expenses between Commission jurisdictional customers and other customers. These allocations are based on the results of the cost of service study that is discussed in my testimony.

Schedule A-1 presents the requested overall increase in retail revenue requirements. Schedule A-1 demonstrates that the adjusted test year rate of return for ACC jurisdictional operations was 2.63% on fair value rate base of $7,713,316,000. The rate of return on fair value rate base resulting from the requested increase of $448,194,000 is just 6.16%, over 250 basis points less than the return recommended by APS Witness William Avera. Schedule A-1 also notes that net increase to customers is $278.2 million because a portion of the total increase would have been passed through to customers through the PSA had it not been reclassified into base rates.

Schedule B-1 provides the calculations of rate base for Total Company and ACC jurisdictional operations. The jurisdictional operations rate base calculations were developed through the cost of service model that is discussed later in my testimony.

I also sponsor portions of the C schedules that exhibit the pro forma adjustments to the test year and the jurisdictional splits of the pro forma adjustments between total Company and ACC jurisdictional operations. The sponsorship of the individual pro forma adjustments is noted on Schedule C-2.

Q. YOU INDICATED THAT THE SFR A-1 SCHEDULE DEMONSTRATES THAT THE REQUIRED INCREASE IS $448.2 MILLION. WOULD YOU PLEASE ELABORATE ON THAT POINT?

A. Yes. The increase of $448.2 million is required to allow APS to earn a reasonable rate of return. APS seeks an effective net annual base revenue increase of $ 278.2 million based on annualized test year sales – an amount that includes a $264.3 million increase in non-fuel base rates and a net increase to fuel-related electric rates of $13.9 million. The $448.2 million base rate increase sought in this application includes $183.9 million of fuel and purchased power costs. However, the Company will recover $170.0 million of that amount under the normal operation of the PSA. Therefore, taking into consideration the reclassification of PSA revenues to base fuel revenues, as called for in the Commission-approved PSA Plan of Administration the Company's effective net revenue increase request is $278.2 million.

Q. HAS APS COMPUTED THE EFFECTIVE RATE INCREASES FOR TYPICAL CUSTOMERS?

A. Yes. Attachment DJR-6 to my testimony presents bill comparisons for typical residential, general service, and industrial customers. The bill comparisons include several factors that enable one to make "apples to apples" comparisons. For example, today, transmission costs are recovered in two elements of customers' bills—the TCA and base rates. APS is proposing that these elements be combined and shown as the TCA for future bills. Also, the bill comparisons show the effect of increased fuel in base rates and the resulting reset of the PSA Forward Component to zero when new base rates resulting from this proceeding become effective. For example, for the typical residential customer using 1,169 kWh per month, the increase under proposed base rates is a net $15.49 per month. The monthly total net increase for a typical small general service

customer is $93.43. Similarly, the monthly total net increase for a typical industrial customer is $23,798.

Q. PLEASE DESCRIBE THE SFR "G" SCHEDULES.

A. The following is a summary of these Schedules:

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

Q. DO YOU HAVE ANY ADDITIONAL SCHEDULES RELATED TO THE COST-OF-SERVICE STUDY THAT YOU ARE SPONSORING?

A. Yes. The following Schedules also relate to the study:

- Schedule GJ is a summary of the cost-of-service study showing the jurisdictional separation of rate base costs, revenues, and operating expenses.
- Schedule GE-1 is a summary of the cost-of-service study showing, by retail customer class, the allocation of total ACC allocated rate base costs, revenues, and operating expenses and the rate-of-return for each major customer class.

- Schedule GE-2 is a summary of the cost-of-service study showing, by each general service subclass, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.

- Schedule GE-3 is a summary cost-of-service study showing, by each residential subclass, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.

IV. PRO FORMA ADJUSTMENTS

Q. ARE YOU RESPONSIBLE FOR THE PREPARATION OF ANY PRO FORMA ADJUSTMENTS TO THE TEST YEAR?

A. Yes. I sponsor the pro forma adjustment that increased operating expenses to recognize that portion of lobbying costs that should be recoverable from customers and the pro forma that adjusted operating income to recognize the financial impacts of providing discounts to customers who participate in the Company's SurePay and AutoPay programs.

Q. WHAT ARE THE BASIS FOR THE PRO FORMAS?

A. As discussed in the testimony of APS Witness Donald Brandt and acknowledged in Decision No. 69663, APS's lobbying activities benefit APS customers, and this pro forma calculates that portion (50%) of the Company's lobbying expenses that the Commission deemed acceptable for recovery in Decision No. 69663. The SurePay and AutoPay discounts were ordered by the Commission in Decision No. 69663 and approved in Decision No. 69923 (September 27, 2007). The pro forma adjustment annualizes the impact of those discounts for the full test year.

Q. PLEASE DESCRIBE THE LOBBYING PRO FORMA ADJUSTMENT.

A. Lobbying costs are booked "below the line" in accordance with FERC accounting practices. The pro forma adjustment moves 50% "above the line"

for recovery in retail rates. The pro forma adjustment increases Administrative and General Expenses by $1,455,000 resulting in a reduction in Operating Income of $882,000. (*See* Attachment DJR-7 and SFR Schedule C-2, page 11, column 31.)

Q. PLEASE DESCRIBE THE SUREPAY/AUTOPAY PRO FORMA ADJUSTMENT.

A. The adjustment reflects the decreased revenue due to the $0.48/month discount offered to customers in accordance with Decision No. 69663 and approved by the Commission in Decision No. 69923. The pro forma reflects the revenue impacts had the discount been in effect for the full year at end of test period participation levels. The pro forma adjustment reduces revenue by $769,000 and operating income by $466,000. (*See* Attachment DJR-8 and SFR Schedule C-2, page 11, column 32.)

V. IMPACT FEES

Q. IS APS PROPOSING A HOOK-UP OR IMPACT FEE IN THIS APPLICATION?

A. Yes. In the deliberations that culminated in Decision No. 69663 and in other cases involving APS and other utilities, the Commission's desire to have growth contribute a greater share to funding growth has been evident. The Commission has an open docket on hook-up fees but, as yet, no decisions or rules have been promulgated. Given the Commission's direction on the topic of hook-up fees, APS has developed a hook-up fee proposal, designated the "Impact Fee." The Impact Fee would be charged to all applicants requesting electric service and the actual fee would depend on the service entrance size ("SES") that is required to serve the customer.

SFR Schedule A-1 provides the total ACC jurisdictional revenue requirements that must be generated by APS customers. These revenue requirements include an attrition adjustment as discussed in the testimony of APS Witness Daniel Kearns. The revenue requirements can be met through base rates or a combination of base rates and revenue generated through Impact Fees. The rate designs discussed in the testimony of APS Witness Greg DeLizio and the results depicted on the SFR "H" schedules assume no revenue from the Impact Fee. To the extent the Commission elects to recover a portion of future attrition through the Impact Fee, the final rate designs that result from this application will be adjusted across the board.

Q. PLEASE DESCRIBE THE RELATIONSHIP BETWEEN THE APS IMPACT FEE PROPOSAL AND THE APS LINE EXTENSION POLICY, SCHEDULE 3.

A. In Decision No. 70185, the Commission approved revisions to Schedule 3 that requires new customers to pay for infrastructure investment required to serve them. The result of the Decision is that APS no longer performs economic feasibility analyses on line extensions, and refund provisions in previous versions of Schedule 3 were eliminated. The Decision also required that proceeds received from customers through the provisions of Schedule 3 be booked as Contributions in Aid of Construction ("CIAC"). The proposed Impact Fee will collect certain growth-related expenses that are either caused by Schedule 3 or not recovered through Schedule 3. Both contribute to customer growth-related earnings attrition. The additional growth-related costs used as the proxy for developing the proposed Impact Fee are: 1) the annual capital carrying cost of what I will call the "tax asset" associated with Schedule 3

CIAC; and 2) the anticipated increases in operations and maintenance expenses that are customer-growth related.

Q. HOW WAS THE PROPOSED IMPACT FEE DEVELOPED?

A. Simply put, the APS proposal started with historical information to determine some of the costs APS has incurred since our last rate decision associated with incremental customer growth, but which would not have been recovered even if Schedule 3 had been in effect. APS then applied that historical cost as a proxy for going-forward costs to determine the Impact Fee applicable to prospective new meter sets.

This approach is not intended to capture each and every incremental cost of serving a new customer. It is intended to be a simple and practical response to a complex issue, essentially by using history as a measure for a level of identifiable incremental expenses that will be incurred to serve an incremental new customer.

Q. PLEASE EXPLAIN THE TAX ASSET CAPITAL CARRYING COSTS IN MORE DETAIL.

A. Schedule 3 proceeds are booked as CIAC. APS experiences an immediate income tax cost because CIAC proceeds are treated as income for tax purposes. This tax cost is, effectively, capitalized and included in APS's rate base. Like other rate base components, this tax "asset" has an annual carrying cost that produces an increased APS revenue requirement equal to the pre-tax cost of capital plus property taxes and depreciation. In this instance, the capitalized tax cost of CIAC has no depreciation or property tax component. Thus, the pre-tax cost of capital times the amount of the tax asset equals its annual carrying cost. The APS Impact Fee proposal would recover the carrying cost of that tax asset

from new customers rather than spreading that cost over all customers. Based on the rate of return authorized in our last rate case, APS used a pre-tax carrying cost of 13% to determine the revenue requirement associated with the tax asset. That carrying cost was applied to an estimated CIAC proceeds stream of approximately $520 million based on the growth-related plant investment closings in 2006 and 2007 that would have been collected under the current version of Schedule 3 had it been in effect. This yields Impact Fee revenue requirement of $27 million for un-recovered customer costs in rate base ($520 million x .40 x .13 = $27 million, using a 40% composite federal and state income tax rate).

Q. SCHEDULE 3 IN ITS CURRENT FORM WAS NOT IN EFFECT DURING 2006 AND 2007. WHY DID YOU CALCULATE THE IMPACT FEE AS IF IT WERE?

A. The Company's historical analysis was used to develop a proxy for the going-forward expenses of growth that form a component of Mr. Kearns' attrition adjustment. On a going forward basis, Schedule 3 will recover a significant portion of the distribution capital cost of growth. What will not be recovered, however, are the carrying cost expense of the tax asset created by Schedule 3 CIAC and certain growth-related increases in operating expenses.

Q. YOU INDICATED THAT THE PROPOSED IMPACT FEE WOULD ALSO REFLECT GROWTH-RELATED INCREASED OPERATIONS AND MAINTENANCE EXPENSES. PLEASE DESCRIBE THAT ASPECT OF THE PROPOSED IMPACT FEE.

A. Growth-related operations and maintenance costs include the costs of incremental personnel for meter reading, service orders, service and inquiry calls as well as incremental costs for such things as transportation, mailings, publications, and postage. Growth also causes increases in costs associated with

maintenance on the additional equipment and increased uncollectible or bad debt costs. Growth-related operating costs also include some portion of the incremental costs incurred by technology and computer systems to manage and enhance our billing and equipment infrastructure monitoring systems, and incremental costs associated with the physical facilities necessary to house the personnel to perform their duties in support of providing electrical service. APS estimated these growth-related costs through a review of each significant cost element of providing service compared to the costs in the last rate case test year. APS estimated the growth related increases in operating and maintenance expenses to be $21 million annually from the end of the last test year through 2007.

Q. DID APS INCLUDE ALL OF THE INCREMENTAL COSTS ASSOCIATED WITH CUSTOMER GROWTH?

A. No. To have the Impact Fee proposal remain true to the goal of simplicity, APS chose to be conservative in the determination of customer-growth related incremental costs. For example, the calculation excluded generation plant projects that increased generation capacity as well as the operations and maintenance costs associated with those projects. The calculations also excluded distribution costs that are incurred as a result of customer growth but were not included in the Schedule 3 plant closing calculation. Finally, the calculation excluded any allocation of administrative and general operating and maintenance expenses even though such allocations have increased as a result of services provided to the incremental personnel hired for increased meter reading, service calls and similar services.

Q. WHAT ARE THE COSTS THAT APS PROPOSES WOULD BE RECOVERED UNDER THE PROPOSED IMPACT FEE?

A. APS estimates the costs to be $53 million annually ($27 million + $21 million plus an adjustment for inflation to 2010). Because of the current volatility in the Arizona real estate market, the selection of the growth base for determining the actual Impact Fee charge is criticial. For example, previous forecasts projected that in 2010, APS would install 36,000 new meter sets. Using the forecast of new meter sets that is the basis for the projections contained in this application, the cost per meter set would be $1,475 per meter set on average. However, more recent forecasts that recognize the current market conditions, indicate that near term meter sets are significantly fewer and higher levels of activity will not occur until after 2010. Because of this volatility, the proposed fee is based on the average number of actual and forecast meter sets for the five-year period ending 2012. Using this average, real estate volatility is mitigated since the five-year period includes years of strong activity, the current weak market and recovery at the end of the forecast period. Using the five-year average and target recovery of $53 million, the average cost per meter set is $2,100. The fee for a typical residential customer would be $1,300. Because of continuing real estate market volatility, the calculation of the Impact Fee and its anticipated revenue impact will need to be updated as this rate proceeding progresses.

Q. UNDER THE APS PROPOSAL, WILL ALL NEW CUSTOMERS PAY THE SAME IMPACT FEE?

A. No. The Impact Fee paid by a customer will be dependant on the SES required by the customer. The proposed Impact Fee Service Schedule is attached as Attachment DJR-9.

Q. WHO WILL BE RESPONSIBLE FOR PAYMENT OF THE IMPACT FEE AND ARE ANY CUSTOMERS EXEMPT FROM PAYMENT OF THE FEE?

A. The first customer requesting permanent service at the service location will be responsible for paying for the Impact Fee. For example, in the case of subdivisions, typically the first customer who requests service at a location is the homebuilder. In the case of custom homes, the person requesting service may be the homebuilder or the homeowner. Since the Impact Fee is a new charge, there will be no "grandfathering"; all customers requesting a new permanent service would be required to pay the Impact Fee.

VI. COST-OF-SERVICE STUDY

Q. DID THE COMPANY CONDUCT AN EMBEDDED COST-OF-SERVICE STUDY IN THE DEVELOPMENT OF ITS PROPOSED RATE SCHEDULES?

A. Yes. APS conducted an embedded cost-of-service study using the twelve-month period ending December 31, 2007 as the test period ("test year"). That is, the Company analyzed its historical costs, customer class sales and load characteristics during this period and used those results to allocate the various items of plant and operating expenses to each customer class. This study was a major input for designing the Company's proposed rates. The study results provided a rate of return for each customer class as well as the functionalization, classification, and allocation of costs.

Q. WHAT DO YOU MEAN BY EMBEDDED COSTS?

A. An embedded cost of service study is based on the actual costs and operating experience of the utility during the selected test year with certain adjustments for normalizing and/or annualizing known and measurable changes. For example, during the twelve-month test period ending 12/31/2007, APS received approval

to increase retail rates. The test year was annualized to reflect revenues as if the rate increase had been in effect for the entire twelve-month period. Similarly, known and measurable cost changes, such as labor costs, costs of employee benefits, taxes and fuel costs, are included as adjustments to the historical data.

Q. ARE THERE ALTERNATIVE METHODS OF PERFORMING COST OF SERVICE ANALYES?

A. Yes, cost of service analyses can also be performed on a marginal or incremental cost basis. Marginal cost analyses examine the costs of providing the next increment of output. For example, marginal cost analyses of distribution facilities may examine the cost of connecting another customer or serving the next kilowatt of demand. The marginal cost of power supplies may examine the cost of obtaining the next kilowatthour of energy or the next kilowatt of capacity. The results of marginal cost of service analyses must ultimately be adjusted so that the marginal costs equate to the utility's revenue requirements.

Q. DID APS PERFORM A MARGINAL COST STUDY IN SUPPORT OF THIS RATE APPLICATION?

A. APS did not perform a detailed marginal cost of service study. Our practice is to support rate applications with embedded cost analyses. However, marginal cost concepts are utilized in developing seasonal and time-of-use cost differentials.

Q. WAS THE USE OF A TWELVE-MONTH TEST YEAR ENDING DECEMBER 31, 2007 SUITABLE FOR THIS COST-OF-SERVICE STUDY?

A. Yes. The test year data provides the most recent available twelve-month period financial and operational information, and is generally as consistent with the Company's revenue requirements as any historical test period can be. However, the Company's analysis does include a number of pro forma adjustments to the

test year that reflect known and measurable changes to its cost of service that have occurred since the test year, as well as other adjustments to normalize the test period. The Company has included these pro forma adjustments in its analysis in order to obtain a better relationship between revenues, expenses, and rate base at the time closer to when the proposed rates are expected to be in effect. For example, wages and salaries are adjusted through a pro forma adjustment to account for current levels and employee count.

Q. WHAT DO YOU MEAN BY "NORMALIZING" THE TEST YEAR INFORMATION?

A. Normalization refers to eliminating the effect of conditions or situations that would not ordinarily occur or be expected to occur in a normal test year, or that recur periodically but should be averaged out over a period of years. For example, the Company would normalize the revenue impact of an abnormally hot summer to better reflect APS's revenue stream during average summer months. The purpose of normalization is to produce a test year that will be more generally representative of conditions that will exist during the period in which the proposed rates will be in effect.

Q. HOW DO YOU TREAT PRO FORMA AND NORMALIZATION ADJUSTMENTS TO THE TEST YEAR IN YOUR COST-OF-SERVICE STUDY?

A. Other APS witnesses sponsor a number of pro forma adjustments that were incorporated into the test year used during the cost-of-service study. APS witnesses Jason La Benz, Mr. Ewen, Mr. DeLizio and Mr. Kearns list, by rate base, revenue, and expense category, the monetized amount of each proposed pro forma adjustment. These amounts were then functionalized, classified, and allocated to the retail and wholesale customer classes as part of the process in

performing the cost-of-service study. The adjusted test year cost-of-service study reflects each of the Company's proposed pro forma adjustments.

Q. WOULD YOU DISCUSS THE DEVELOPMENT OF THE EMBEDDED COST ALLOCATION STUDY?

A. This study was prepared using industry accepted cost-of-service functionalization, classification, and allocation principles, and is generally consistent with the historical APS practices that the Commission has approved in the past.

"Functionalization" refers to the process of attributing a particular rate base or expense item to a particular function – namely Production, Transmission, or Distribution – in the provision of electric service. An easy example is the assignment of the costs of building and operating the Company's power plants to the Production function.

"Classification" refers to the process of determining the factor or factors that drive the magnitude of the cost. For example, if a cost is driven by the amount of energy consumed, it is classified as Energy; if a cost is driven by the rate at which energy is consumed, it is classified as Demand; and if a cost is driven by the number of customers taking service on the APS system irrespective of either the demand or energy utilized, it is classified as Customer.

"Allocation" occurs once a cost has been functionalized and classified. This is the process in which allocation factors (such as peak demand contribution, energy or customers) are applied to spread the costs to particular jurisdictions, customer classes, and rate schedules. A simple example is the allocation of

energy related costs by kilowatt-hour ("kWh") consumption to different customer classes.

In the cost-of-service study, the expense and rate base items that comprise APS's costs were grouped into major categories, such as Plant in Service or Operating & Maintenance ("O&M") Expense. Each of these categories was first functionalized into Production, Transmission, or Distribution related costs, then classified as Demand, Energy, or Customer related. Allocation factors based on kilowatts, kilowatt-hours, and number of customers were then developed so that allocations of the functionalized and classified costs could be made to the federal and state jurisdictions and to the various retail customer classes and sub-classes. When necessary, APS implemented adjustments to these allocations to reflect unusual or changing circumstances.

Q. HOW DID YOU ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?

A. Production-related assets are generally designed and built to enable the Company to meet its system peak load. Therefore, the costs associated with these investments are allocated based on the average of the system peak demands occurring in the months of June, July, August, and September ("4CP") to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its cases before FERC and prevents the potential for "stranded" costs that cannot be recovered from either jurisdiction. It has also been accepted as the jurisdictional allocation methodology by the Commission for many years.

Within the ACC-jurisdictional customer classes, production costs were allocated based on the Average and Excess Demand ("AED") method, which I describe in detail below.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the cost of service study.

Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class' peak load, which may or may not be coincident with the system peak load. Thus, allocations of costs related to distribution substations and primary distribution lines are made based on non-coincident peak loads ("NCP"). Allocations of costs related to distribution transformers and secondary distribution lines are made based on the summation of the individual peak loads or demands of all customers within a particular customer class ("ΣNCP").

Q. PLEASE DESCRIBE THE AVERAGE AND EXCESS DEMAND METHOD AND WHY IT WAS SELECTED AS AN APPROPTIATE METHOD FOR ALLOCATING PRODUCTION COSTS.

A. In Decision No. 69663, the Commission directed that APS use an energy-weighted method to allocate production demand costs – that is, the costs associated with the Company's nuclear, coal, and gas-fired generation facilities – among retail customer classes. The AED method is one of the most widely accepted energy weighted allocation methods. It allocates a portion of production costs based on a customer class's peak demand contribution and the balance on that class's energy-based or average demand contribution. In doing so, the AED allocation method considers the fact that APS's production facilities provide service during both peak and non-peak hours of the year but also

recognizes that average demand is already included in peak demand, and thus avoids double-counting of a customer's average demand when allocating costs. As a result, the AED method requires all customers to contribute an amount to meeting the fixed costs the Company incurs in providing generation services.

Q. DID YOU MAKE ANY OTHER CHANGES IN ALLOCATION METHODS IN THIS COST OF SERVICE STUDY COMPARED TO STUDIES PERFORMED IN SUPPORT OF PREVIOUS APS RATE CASES?

A. Yes, in our last rate case, an intervenor witness suggested the adoption of an hourly allocation method to allocate fuel and purchased power costs. While the hourly allocation method was not specifically ordered in Decision No. 69663, APS believes that allocation of energy costs with consideration of hourly variations in costs has merit, as explained below. Thus, the Company has used the hourly allocation method in the Cost of Service Study prepared in support of this filing.

Q. PLEASE DESCRIBE THE HOURLY ENERGY ALLOCATION METHOD.

A. The hourly energy allocation method examines customer class hourly load shapes and hourly energy prices to come up with a weighted energy cost. This weighted energy cost better matches each customer class's revenue responsibility with costs. For example, a customer class that uses more of its energy during peak summer hours should be allocated higher average fuel and energy costs than a customer class whose energy consumption is more off peak.

Q. PLEASE EXPLAIN THE "ALL OTHER" OR NON-ACC-JURISDICTIONAL SEGMENT OF YOUR COST-OF-SERVICE STUDY.

A. The "All Other" segment, which appears as a column in the cost-of-service study, represents the rate base, expenses, and revenues associated with service to

long-term firm FERC jurisdictional resale customers that APS serves, as well as long-term transmission services APS provides to a number of entities. Because APS plans and utilizes Company facilities in order to fulfill these obligations, APS has allocated and assigned a portion of APS production and distribution facilities to these non-jurisdictional customers in the same manner as it would to the Company's classes of retail jurisdictional customers in preparing the cost-of-service study, except that for jurisdictional purposes, APS used a 4CP demand allocator for the reasons described earlier.

Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COST-OF-SERVICE STUDY.

A. In addition to the transactions described for inclusion in the "All Other" column depicted in the cost-of-service study, APS makes sales to parties that are not traditional APS retail customers. In order to be certain that all the benefits of such transactions flow through to retail customers, the revenues derived from these transactions, which more than cover the incremental costs associated with producing or acquiring the required energy, are allocated to all customers. Thus, the entire margin or profit that APS realizes from these non-retail transactions is attributed to each class through the revenue credit, which benefits all customers by lowering the amount of their overall revenue requirements.

APS also treats non-firm short-term transactions and a number of other small items, such as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service Revenues, Sales to Rate Schedule E-36 customers, and Other Electric Revenues, as revenue credits.

Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND RATE OF RETURN BASED ON THE ADJUSTED TEST YEAR?

A. Yes. In addition to establishing the Production, Transmission, and Distribution functions and the Demand, Energy, and Customer classifications for each class of retail business, the original cost rate of return for each class under both test year and proposed rates appears in the SFR "G" Schedules.

Q. BASED ON THE RESULTS OF YOUR ADJUSTED TEST YEAR COST-OF-SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?

A. The "G", GJ, and GE Schedules plainly show that there are disparities in the rates of return that the different customer classes are providing to the Company. Although the disparities have decreased due to the rate designs implemented as a result of the rates implemented by previous ACC decisions, the residential class continues to provide a lower rate of return to the Company than does the general service class. Specifically, under current rates and adjusted operating expenses, the residential class rate of return is 2.85% while the general service class rate of return is 5.04%. Overall, the retail rate of return on an adjusted original cost rate base under current rates is 3.79%.

VII. TRANSMISSION COSTS

Q. WOULD YOU EXPLAIN HOW TRANSMISSION COSTS WERE TREATED IN THE COST-OF-SERVICE STUDY?

A. Yes. Consistent with the methods adopted in our last rate cases, the revenue requirement for transmission services was computed based on the FERC-jurisdictional rates found in the APS Open Access Transmission Tariff ("OATT").

Q. HOW DID YOU ALLOCATE TRANSMISSION COSTS TO THE RETAIL CUSTOMERS CLASSES?

A. It is unnecessary to perform interclass allocations of transmission costs. These costs are directly assigned. The APS OATT provides the class rate elements for

each of the FERC-regulated transmission and ancillary service costs. Under the requirements of Decision No. 69663, the APS retail rates were re-structured so the transmission component of the rates reflect the OATT charges. In this application, the Company proposes that the FERC-regulated charges be removed from base rates and directly charged to customers through a separate transmission rate schedule, TCA-1, that would directly incorporate by reference the Company's then-effective OATT charges. APS is proposing to modify the existing TCA-1 to reflect this change. Effectively, the new TCA-1 will reflect the transmission cost found in base rates today, plus the then-effective adjustment that reflects the increased OATT charges. When the FERC-regulated transmission rates are changed, APS will refile the retail transmission rate schedule TCA-1 with the new charges. The existing TCA Plan of Administration will no longer be needed. A copy of the proposed, revised Rate Schedule TCA-1 is attached (Attachment DJR-10).

VIII. SCHEDULE 3

Q. IS APS PROPOSING ANY CHANGES TO THE LINE EXTENSION POLICY, SCHEDULE 3?

A. Decision No. 69663 resulted in changes to Schedule 3 that included the replacement of a free footage allowance with an equipment allowance. In that same decision, the Commission ordered the Company to file another revision to the extension policy that would eliminate all free allowances and line extension policy economic feasibility tests. APS complied with that aspect of Decision No. 69663. In Decision No. 70185, the Commission approved a revised policy that requires all customers to fund 100% of line extensions with the exceptions of residential customers who are located on Native American Reservations and customers who are "grandfathered" under the terms of the version of Service

Schedule 3 that was in effect when the customer executed an extension agreement or is under the terms of a transition period approved by the Commission.

In this application, APS is requesting some minor changes to Schedule 3 to simplify and clarify the implementation of the schedule. These changes include adding a definition to describe "system facilities" and modifying the introductory paragraph of Service Schedule 3 to allow for the possibility of serving customers at distribution voltages higher than the traditional 21kV. The changes also clarify the method that is used to determine costs for local facilities in residential subdivisions. The cost for local facilities in such subdivisions does not vary significantly on a per lot basis, therefore, APS will use an average "per lot" cost for local facilities. With this approach, developers will know the local facilities costs in advance and can incorporate the costs in their project financial plan. A redlined revised Schedule 3 is attached (Attachment DJR-11).

IX. CONCLUSION

Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO COST OF SERVICE MATTERS IN THIS PROCEEDING?

A. The cost-of-service study indicates that APS's current rate schedules produce rates of return for each customer class that vary greatly from each other and from the overall average and required rate of return. While moving to cost-based pricing is an appropriate goal, moderation in changes is appropriate. Certain changes to the cost of service model, largely based on customer and Staff suggestions, also indicates our goal to better identify the costs of providing service to customers that are reflected in our retail rates. APS's approach to cost of service and rate design attempts to provide better price signals to customers.

Whether through improving relative rates of return or offering pricing alternatives, such as hook-up fees that address growth issues, there is significant benefit in providing customers with the correct price signals. Programs such as energy efficiency or demand-side management are more effective if consumers understand the real cost of electric service.

I recommend the Commission approve APS's request to remove transmission costs from base rates and allow all transmission costs to flow through the Rate Schedule TCA-1. This will insure that the FERC-authorized transmission charges are clearly differentiated from the ACC-regulated charges.

Q. DO YOU HAVE ANY OTHER CONCLUSIONS REGARDING YOUR DIRECT TESTIMONY?

A. My testimony provides a discussion of an approach to hook-up fees that APS believes adds another dimension to meeting the Commission's goal of making growth pay for itself when added to the important first step taken by the Commission in Decision No. 70185. Additional revenues generated by approval of the Impact Fee could mitigate a portion of the attrition adjustment needed by the Company to enable it to continue to provide safe, reliable electric service to Arizona customers, and, thus, I recommend that the Commission approve Service Schedule 6.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A

Statement of Qualifications

David J. Rumolo

David J. Rumolo is Arizona Public Service Company's Manager of State Pricing. He has over 32 years experience in the electric utility business as a consultant and utility professional. Mr. Rumolo holds Bachelor of Science Degrees in Electrical Engineering and Business (Finance as an area of emphasis) from the University of Colorado. He is a registered professional engineer in the states of Arizona, California, and New Mexico.

Mr. Rumolo's areas of expertise include utility Rate Schedule design; embedded and marginal cost analysis; formulation of utility service policies; contract development and negotiation; utility valuation analyses; and evaluation of utility revenue requirements. Mr. Rumolo has testified on utility matters before state regulatory bodies in the states of Arizona, Colorado, Florida, and Wyoming and before judicial bodies in the states of Arizona and California. Mr. Rumolo is also experienced in the many aspects of electric utility planning and design including preparation of long range resource plans; transmission and distribution system long range planning; system protection analyses; and reliability assessments.

Mr. Rumolo has held his current position at Arizona Public Service Company for approximately seven years. Prior to assuming that position, he served as the Manager of Transmission and Market Structure Assessment for Pinnacle West Energy Corporation ("PWEC"). Before joining PWEC, Mr. Rumolo had a 15-year career as a consultant with Resource Management International, Inc., where he provided utility Rate Schedule and engineering consulting services to utility clients across the United

States and overseas. He began his career providing consulting services to utility clients when he joined the firm of Miner and Miner Consulting Engineers in Greeley, Colorado where he became the Manager of Planning and Rates. He later became a partner in Electrical Systems Consultants where he focused on cost of service and rate analyses, as well as transmission and distribution planning.

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2007
($)

Line No.	Description	GJ ELECTRIC TOTAL (1)	GJ ACC JURISDICTION (2)	GJ ALL OTHER (3)
	SUMMARY OF RESULTS			
1	**DEVELOPMENT OF RATE BASE**			
2	ELECTRIC PLANT IN SERVICE	$11,101,113,465	$9,562,449,495	$1,538,663,970
3	GENERAL & INTANGIBLE PLANT	$824,610,420	$773,798,357	$50,812,063
4	LESS: RESERVE FOR DEPRECIATION	($4,637,471,644)	($4,094,858,988)	($542,612,656)
5	OTHER DEFERRED CREDITS	($874,221,269)	($835,666,528)	($38,554,741)
6	WORKING CASH	($103,177,367)	($89,955,067)	($13,222,300)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$262,229,116	$238,222,612	$24,006,504
8	ACCUM. DEFERRED TAXES	($1,206,568,000)	($1,018,730,127)	($187,837,873)
9	REGULATORY ASSETS	$200,777,000	$177,892,524	$22,884,476
10	DECOMMISSIONING FUND	$379,346,784	$370,097,912	$9,248,872
11	GAIN FROM DISP. OF PLANT	($36,606,000)	($35,958,252)	($647,748)
12	MISCELLANEOUS DEFERRED DEBITS	$63,879,000	$60,303,509	$3,575,491
13	CUSTOMER ADVANCES	($94,801,000)	($94,801,000)	$0
14	CUSTOMER DEPOSITS	($71,311,000)	($71,311,000)	$0
15	PROFORMA ADJUSTMENTS	$428,065,999	$418,481,024	$9,584,975
16	**TOTAL RATE BASE**	**$6,235,865,504**	**$5,359,964,470**	**$875,901,034**
17				
18	**DEVELOPMENT OF RETURN**			
19	REVENUES FROM RATES	$2,562,201,445	$2,509,499,263	$52,702,182
20	PROFORMA TO REVENUES FROM RATES	$127,947,826	$127,947,826	$0
21	OTHER ELECTRIC REVENUE	$122,862,554	$94,461,282	$28,401,272
22	**TOTAL OPERATING REVENUES**	**$2,813,011,825**	**$2,731,908,371**	**$81,103,454**
23				
24	**OPERATING EXPENSES**			
25	OPERATION & MAINTENANCE	$1,696,105,908	$1,734,914,608	($38,808,700)
26	ADMINISTRATIVE & GENERAL	$171,762,904	$156,665,708	$15,097,196
27	DEPRECIATION & AMORT EXPENSE	$370,958,999	$334,402,153	$36,556,846
28	AMORTIZATION ON GAIN	($6,399,683)	($6,284,171)	($115,512)
29	REGULATORY ASSETS	($5,529,000)	($5,529,000)	$0
30	PROFORMA ADJUSTMENTS	$181,295,600	$175,981,833	$5,313,767
31	TAXES OTHER THAN INCOME	$127,647,967	$110,410,937	$17,237,030
32	INCOME TAX	$36,196,211	$28,234,394	$7,961,816
33	**TOTAL OPERATING EXPENSES**	**$2,572,038,906**	**$2,528,796,463**	**$43,242,443**
34				
35	**OPERATING INCOME**	**$240,972,919**	**$203,111,908**	**$37,861,011**
36				
37	**RETURN**	**$240,972,919**	**$203,111,908**	**$37,861,011**
38				
39	**RATE OF RETURN (PRESENT)**	**3.86%**	**3.79%**	**4.32%**
40				
41	**INDEX RATE OF RETURN (PRESENT)**	**1.00**	**0.98**	**1.12**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2007
($)

Line No.	Description	TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	E-38,221 (Water Pumping) (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
		<---------- GE-1 ---------->					
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$9,562,449,495	$5,258,329,165	$4,090,238,900	$61,829,353	$105,706,610	$46,345,467
3	GENERAL & INTANGIBLE PLANT	$773,798,357	$465,896,446	$289,187,290	$5,592,993	$10,311,412	$2,810,216
4	LESS: RESERVE FOR DEPRECIATION	($4,094,858,988)	($2,238,230,541)	($1,772,673,634)	($29,798,198)	($38,956,682)	($15,199,933)
5	OTHER DEFERRED CREDITS	($835,666,528)	($453,462,100)	($365,020,680)	($7,798,308)	($7,450,302)	($1,935,138)
6	WORKING CASH	($89,955,067)	($48,173,310)	($39,889,578)	($624,223)	($871,902)	($396,054)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$238,222,612	$124,780,622	$108,564,915	$2,051,009	$2,046,903	$779,163
8	ACCUM. DEFERRED TAXES	($1,018,730,127)	($565,733,377)	($428,807,900)	($6,089,919)	($12,463,198)	($5,635,733)
9	REGULATORY ASSETS	$177,892,524	$84,798,083	$89,712,194	$2,094,206	$1,001,771	$286,270
10	DECOMMISSIONING FUND	$370,097,912	$176,682,840	$187,092,396	$4,373,647	$1,613,780	$335,249
11	GAIN FROM DISP. OF PLANT	($35,958,252)	($18,540,939)	($16,908,490)	($336,775)	($142,763)	($29,285)
12	MISCELLANEOUS DEFERRED DEBITS	$60,303,509	$35,289,294	$23,613,777	$473,373	$730,333	$196,732
13	CUSTOMER ADVANCES	($94,801,000)	($59,880,665)	($30,589,580)	($4,176,598)	($154,157)	$0
14	CUSTOMER DEPOSITS	($71,311,000)	($34,699,804)	($35,154,131)	($749,691)	($488,127)	($219,247)
15	PROFORMA ADJUSTMENTS	$418,481,024	$227,404,691	$183,122,375	$3,301,225	$3,463,347	$1,189,386
16	TOTAL RATE BASE	**$5,359,964,470**	**$2,954,460,405**	**$2,282,487,853**	**$30,142,093**	**$64,347,024**	**$28,527,095**
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$2,509,499,263	$1,301,621,327	$1,159,806,395	$24,733,843	$16,104,307	$7,233,391
20	PROFORMA TO REVENUES FROM RATES	$127,947,826	$45,411,639	$80,362,562	$642,344	$1,268,670	$262,611
21	OTHER ELECTRIC REVENUE	$94,461,282	$47,608,491	$42,642,678	$867,311	$3,062,694	$280,107
22	TOTAL OPERATING REVENUES	**$2,731,908,371**	**$1,394,641,457**	**$1,282,811,635**	**$26,243,498**	**$20,435,671**	**$7,776,109**
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$1,734,914,608	$894,002,949	$806,841,743	$17,639,391	$13,916,265	$2,514,261
26	ADMINISTRATIVE & GENERAL	$156,665,708	$93,001,024	$59,893,710	$1,099,388	$2,052,403	$619,184
27	DEPRECIATION & AMORT EXPENSE	$334,402,153	$184,647,547	$142,488,185	$2,388,768	$3,512,332	$1,365,321
28	AMORTIZATION ON GAIN	($6,284,171)	($3,227,613)	($2,966,664)	($59,668)	($25,079)	($5,148)
29	REGULATORY ASSETS	($5,529,000)	($2,850,885)	($2,599,877)	($51,783)	($21,952)	($4,503)
30	PROFORMA ADJUSTMENTS	$175,981,833	$83,951,653	$89,181,791	$1,751,985	$814,151	$282,253
31	TAXES OTHER THAN INCOME	$110,410,937	$60,561,062	$47,417,066	$726,864	$1,188,852	$517,093
32	INCOME TAX	$28,234,394	$368,154	$27,578,153	$665,913	($981,244)	$603,418
33	TOTAL OPERATING EXPENSES	**$2,528,796,463**	**$1,310,453,891**	**$1,167,834,107**	**$24,160,858**	**$20,455,728**	**$5,891,879**
34							
35	OPERATING INCOME	**$203,111,908**	**$84,187,567**	**$114,977,528**	**$2,082,640**	**($20,057)**	**$1,884,230**
36							
37	RETURN	**$203,111,908**	**$84,187,567**	**$114,977,528**	**$2,082,640**	**($20,057)**	**$1,884,230**
38							
39	RATE OF RETURN (PRESENT)	**3.79%**	**2.85%**	**5.04%**	**6.91%**	**-0.03%**	**6.61%**
40							
41	INDEX RATE OF RETURN (PRESENT)	**0.98**	**0.74**	**1.30**	**1.79**	**-0.01**	**1.71**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2007
($)

Line No.	Description	TOTAL GENERAL SVC (10)	E-20 (Church Rate) (11)	General Ser. TOU (12)	E-30, E-32 (0 - 20 kW) (13)	E-32 (21 - 100 kW) (14)	E-32 (101 - 400 kW) (15)	E-32 (401+ kW) (16)	E-34 (17)	E-35 (18)
		<-- GE-2 -->								
	SUMMARY OF RESULTS									
1	**DEVELOPMENT OF RATE BASE**									
2	ELECTRIC PLANT IN SERVICE	$4,090,238,900	$20,270,023	$43,733,476	$765,376,740	$1,016,058,078	$945,229,684	$863,229,774	$225,758,913	$210,582,212
3	GENERAL & INTANGIBLE PLANT	$289,187,290	$1,246,150	$3,123,873	$60,601,282	$67,375,415	$62,120,656	$60,026,421	$16,732,241	$17,961,253
4	LESS: RESERVE FOR DEPRECIATION	($1,772,673,634)	($8,586,547)	($19,144,744)	($322,714,149)	($429,803,250)	($409,129,378)	($380,868,355)	($101,437,492)	($100,989,720)
5	OTHER DEFERRED CREDITS	($365,020,680)	($1,262,320)	($4,665,454)	($55,048,078)	($76,732,438)	($83,018,018)	($87,826,964)	($26,155,333)	($30,312,075)
6	WORKING CASH	($39,889,578)	($193,819)	($437,479)	($7,036,380)	($9,758,880)	($9,324,859)	($8,645,792)	($2,290,539)	($2,201,831)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$108,564,915	$419,497	$1,354,716	$16,187,004	$23,989,054	$25,306,554	$25,770,229	$7,427,200	$8,110,662
8	ACCUM. DEFERRED TAXES	($428,807,900)	($2,140,403)	($4,559,750)	($82,215,687)	($107,865,404)	($98,803,076)	($89,340,150)	($23,157,531)	($20,725,898)
9	REGULATORY ASSETS	$89,712,194	$197,270	$1,373,643	$8,224,569	$16,374,546	$21,291,812	$24,846,330	$7,900,318	$9,503,709
10	DECOMMISSIONING FUND	$187,092,396	$480,117	$2,747,957	$18,541,525	$35,131,022	$44,379,159	$50,664,199	$15,858,099	$19,290,316
11	GAIN FROM DISP. OF PLANT	($16,908,490)	($80,533)	($186,691)	($2,730,808)	($3,920,503)	($3,979,251)	($3,821,666)	($1,043,271)	($1,145,768)
12	MISCELLANEOUS DEFERRED DEBITS	$23,613,777	$94,556	$271,131	$4,492,207	$5,314,850	$5,164,999	$5,162,663	$1,477,398	$1,635,974
13	CUSTOMER ADVANCES	($30,589,580)	($91,190)	($386,351)	($4,404,365)	($6,832,636)	($7,221,326)	($7,564,799)	($1,976,050)	($2,112,863)
14	CUSTOMER DEPOSITS	($35,154,131)	($104,797)	($444,002)	($5,061,581)	($7,852,197)	($8,298,886)	($8,693,612)	($2,270,915)	($2,428,142)
15	PROFORMA ADJUSTMENTS	$183,122,375	$873,508	$1,991,534	$32,608,521	$43,629,507	$42,261,800	$39,870,607	$10,749,068	$11,137,829
16	**TOTAL RATE BASE**	**$2,282,487,853**	**$11,121,512**	**$24,771,860**	**$426,820,799**	**$565,107,163**	**$525,979,871**	**$482,808,885**	**$127,572,106**	**$118,305,657**
17										
18	**DEVELOPMENT OF RETURN**									
19	REVENUES FROM RATES	$1,159,806,395	$3,457,467	$14,648,518	$166,991,869	$259,059,957	$273,797,147	$286,819,964	$74,922,109	$80,109,364
20	PROFORMA TO REVENUES FROM RATES	$80,362,562	($190,309)	$780,474	$6,845,706	$14,297,677	$18,580,141	$20,121,123	$10,820,011	$9,107,739
21	OTHER ELECTRIC REVENUE	$42,642,678	$140,416	$569,636	$5,501,608	$8,912,017	$10,048,944	$10,721,795	$3,195,249	$3,553,014
22	**TOTAL OPERATING REVENUES**	**$1,282,811,635**	**$3,407,574**	**$15,998,628**	**$179,339,183**	**$282,269,651**	**$302,426,232**	**$317,662,882**	**$88,937,369**	**$92,770,117**
23										
24	**OPERATING EXPENSES**									
25	OPERATION & MAINTENANCE	$806,841,743	$2,402,364	$10,914,372	$105,736,560	$164,518,346	$186,351,932	$201,866,767	$62,072,964	$72,978,439
26	ADMINISTRATIVE & GENERAL	$59,893,710	$266,097	$645,027	$12,334,254	$14,167,708	$13,050,305	$12,444,976	$3,421,658	$3,563,685
27	DEPRECIATION & AMORT EXPENSE	$142,488,185	$666,452	$1,568,707	$25,981,656	$34,256,641	$32,680,091	$30,759,231	$8,290,051	$8,285,357
28	AMORTIZATION ON GAIN	($2,966,664)	($13,762)	($33,366)	($468,687)	($680,489)	($698,488)	($678,021)	($186,906)	($206,945)
29	REGULATORY ASSETS	($2,599,877)	($12,383)	($28,706)	($419,893)	($602,823)	($611,856)	($587,626)	($160,415)	($176,175)
30	PROFORMA ADJUSTMENTS	$89,181,791	$174,472	$538,950	$10,576,700	$17,968,480	$21,031,665	$22,231,463	$8,004,422	$8,655,638
31	TAXES OTHER THAN INCOME	$47,417,066	$234,580	$507,724	$8,818,961	$11,744,117	$10,966,726	$10,038,673	$2,630,841	$2,475,444
32	INCOME TAX	$27,578,153	($219,459)	$417,420	$1,703,747	$8,855,374	$8,767,058	$9,846,057	$422,070	($2,214,115)
33	**TOTAL OPERATING EXPENSES**	**$1,167,834,107**	**$3,498,361**	**$14,530,129**	**$164,263,298**	**$250,227,354**	**$271,537,433**	**$285,921,521**	**$84,494,685**	**$93,361,327**
34										
35	**OPERATING INCOME**	**$114,977,528**	**($90,787)**	**$1,468,499**	**$15,075,886**	**$32,042,297**	**$30,888,799**	**$31,741,361**	**$4,442,684**	**($591,210)**
36										
37	**RETURN**	**$114,977,528**	**($90,787)**	**$1,468,499**	**$15,075,886**	**$32,042,297**	**$30,888,799**	**$31,741,361**	**$4,442,684**	**($591,210)**
38										
39	**RATE OF RETURN (PRESENT)**	**5.04%**	**-0.82%**	**5.93%**	**3.53%**	**5.67%**	**5.87%**	**6.57%**	**3.48%**	**-0.50%**
40										
41	**INDEX RATE OF RETURN (PRESENT)**	**1.30**	**-0.21**	**1.53**	**0.91**	**1.47**	**1.52**	**1.70**	**0.90**	**-0.13**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2007
($)

Line No.	Description	GE-3 TOTAL RESIDENTIAL (19)	RESIDENTIAL E-10 (Interim) (20)	RESIDENTIAL E-12 (21)	RESIDENTIAL EC-1 (22)	RESIDENTIAL ET-1 & ET-2 (23)	RESIDENTIAL ECT-1 & ECT-2 (24)
	SUMMARY OF RESULTS						
1	**DEVELOPMENT OF RATE BASE**						
2	ELECTRIC PLANT IN SERVICE	$5,258,329,165	$276,105,551	$1,506,625,281	$159,566,083	$2,676,130,541	$639,901,708
3	GENERAL & INTANGIBLE PLANT	$465,896,446	$24,341,646	$154,847,444	$12,629,009	$223,216,046	$50,862,302
4	LESS: RESERVE FOR DEPRECIATION	($2,238,230,541)	($117,462,514)	($644,244,435)	($67,968,446)	($1,135,932,170)	($272,622,976)
5	OTHER DEFERRED CREDITS	($453,462,100)	($23,642,185)	($141,721,823)	($13,376,088)	($220,596,094)	($54,125,910)
6	WORKING CASH	($48,173,310)	($2,530,051)	($13,401,852)	($1,498,266)	($24,733,662)	($6,009,480)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$124,780,622	$6,523,192	$36,262,888	$3,864,712	$62,530,578	$15,599,253
8	ACCUM. DEFERRED TAXES	($565,733,377)	($29,705,445)	($163,401,771)	($17,034,326)	($287,268,113)	($68,323,723)
9	REGULATORY ASSETS	$84,798,083	$4,393,780	$25,148,820	$2,749,415	$41,263,905	$11,242,163
10	DECOMMISSIONING FUND	$176,682,840	$9,173,439	$51,217,850	$5,763,550	$87,040,371	$23,487,630
11	GAIN FROM DISP. OF PLANT	($18,540,939)	($973,720)	($5,007,701)	($593,017)	($9,590,772)	($2,375,729)
12	MISCELLANEOUS DEFERRED DEBITS	$35,289,294	$1,842,483	$11,563,212	$978,092	$16,960,242	$3,945,265
13	CUSTOMER ADVANCES	($59,880,665)	($3,080,437)	($19,667,449)	($1,596,635)	($29,369,590)	($6,166,554)
14	CUSTOMER DEPOSITS	($34,699,804)	($1,785,059)	($11,396,944)	($925,222)	($17,019,167)	($3,573,411)
15	PROFORMA ADJUSTMENTS	$227,404,691	$11,930,381	$65,522,486	$6,920,847	$115,269,397	$27,761,580
16	**TOTAL RATE BASE**	**$2,954,460,405**	**$155,131,062**	**$852,346,006**	**$89,479,706**	**$1,497,901,512**	**$359,602,118**
17							
18	**DEVELOPMENT OF RETURN**						
19	REVENUES FROM RATES	$1,301,621,327	$66,959,208	$427,509,795	$34,705,931	$638,404,487	$134,041,906
20	PROFORMA TO REVENUES FROM RATES	$45,411,639	($9,744,773)	$15,077,572	($2,262,941)	$27,349,170	$14,992,611
21	OTHER ELECTRIC REVENUE	$47,608,491	$2,468,596	$13,911,107	$1,489,040	$23,716,736	$6,023,012
22	**TOTAL OPERATING REVENUES**	**$1,394,641,457**	**$59,683,031**	**$456,498,474**	**$33,932,030**	**$689,470,393**	**$155,057,529**
23							
24	**OPERATING EXPENSES**						
25	OPERATION & MAINTENANCE	$894,002,949	$45,715,848	$267,609,420	$27,659,776	$441,154,855	$111,863,051
26	ADMINISTRATIVE & GENERAL	$93,001,024	$4,863,061	$30,231,230	$2,567,949	$45,004,346	$10,334,437
27	DEPRECIATION & AMORT EXPENSE	$184,647,547	$9,680,955	$54,335,930	$5,531,653	$92,881,730	$22,217,279
28	AMORTIZATION ON GAIN	($3,227,613)	($169,411)	($874,871)	($103,333)	($1,665,670)	($414,327)
29	REGULATORY ASSETS	($2,850,885)	($149,721)	($769,992)	($91,183)	($1,474,693)	($365,296)
30	PROFORMA ADJUSTMENTS	$83,951,653	$548,477	$24,586,067	$891,771	$43,809,511	$14,115,826
31	TAXES OTHER THAN INCOME	$60,561,062	$3,179,975	$17,314,178	$1,841,527	$30,840,679	$7,384,703
32	INCOME TAX	$368,154	($2,965,718)	$14,149,920	($2,443,435)	($1,199,400)	($7,173,213)
33	**TOTAL OPERATING EXPENSES**	**$1,310,453,891**	**$60,703,465**	**$406,581,882**	**$35,854,726**	**$649,351,357**	**$157,962,461**
34							
35	**OPERATING INCOME**	**$84,187,567**	**($1,020,434)**	**$49,916,593**	**($1,922,696)**	**$40,119,036**	**($2,904,932)**
36							
37	**RETURN**	**$84,187,567**	**($1,020,434)**	**$49,916,593**	**($1,922,696)**	**$40,119,036**	**($2,904,932)**
38							
39	**RATE OF RETURN (PRESENT)**	**2.85%**	**-0.66%**	**5.86%**	**-2.15%**	**2.68%**	**-0.81%**
40							
41	**INDEX RATE OF RETURN (PRESENT)**	**0.74**	**-0.17**	**1.52**	**-0.56**	**0.69**	**-0.21**

Standard Filing Requirements
Index for Sponsorship

A Schedules		
A-1		Rumolo
A-2 to A-5	Historical	La Benz
	Projected	Kearns

B Schedules		
B-1 *		La Benz
B-2 to B-3 *	Columns 2-5	Kearns
	Column 6	La Benz
B-4 to B-5		La Benz

C Schedules		
C-1 *		La Benz
	Columns 1-5	Kearns
	Columns 6-13	Ewen
C-2 *	Columns 14-30	La Benz
	Columns 31-32	Rumolo
	Column 33	DeLizio
C-3		La Benz

D Schedules		
D-1 to D-3	Historical	La Benz
	Projected	Kearns
D-4		La Benz

E Schedules	
E-1 to E-9	La Benz

F Schedules		
F-1 to F-3	Historical	La Benz
	Projected	Kearns
F-4		Kearns

G Schedules	
G-1 to G-7	Rumolo

H Schedules	
H-1 to H-5	DeLizio

* David Rumolo sponsors the ACC jurisdictional amounts that are computed via the Cost of Service Study.

ARIZONA PUBLIC SERVICE COMPANY
Monthly Bill Impact (Base Rates)

	CURRENT RATES Monthly Bill	PROPOSED RATES Monthly Bill	Monthly $ Change
Residential			
Average kWh per Month	1,169	1,169	
Base Rates	$ 116.20	$ 130.29	$ 14.09
PSA - Forward Component	$ 3.45	$ -	$ (3.45)
PSA - Forward Component - estimated 2/09 (1)	$ 1.23	$ -	$ (1.23)
TCA (2)	$ 1.16	$ 7.24	$ 6.08
subtotal	$ 122.04	$ 137.53	$ 15.49
Impact Fee Credit		$ (2.15)	
Net Bill After Impact Fee Credit		$ 135.38	$ 13.34
Commercial E32			
Average kWh per Month	8,663	8,663	
Base Rates	$ 773.63	$ 865.08	$ 91.44
PSA - Forward Component	$ 25.57	$ -	$ (25.57)
PSA - Forward Component - estimated 2/09 (1)	$ 9.08	$ -	$ (9.08)
TCA (2)	$ 11.70	$ 48.34	$ 36.64
subtotal	$ 819.99	$ 913.42	$ 93.43
Impact Fee Credit		$ (15.91)	
Net Bill After Impact Fee Credit		$ 897.51	$ 77.52
Industrial E34/35			
Average kWh per Month	4,008,132	4,008,132	
Base Rates	$ 245,795	$ 276,247	$ 30,452
PSA - Forward Component	$ 11,832	$ -	$ (11,832)
PSA - Forward Component - estimated 2/09 (1)	$ 4,201	$ -	$ (4,201)
TCA (2)	$ 1,643	$ 11,022	$ 9,379
subtotal	$ 263,471	$ 287,269	$ 23,798
Impact Fee Credit		$ (7,362)	
Net Bill After Impact Fee Credit		$ 279,907	$ 16,436

Impact Fee Revenue	$ 53,000,000
Test Year Adjusted MWh	28,855,123
Impact Fee Revenue/kwh	$ 0.0018368

(1) This is consistent with the Company's requested 3.88 cents/kwh base fuel rate. Assumes that the Forward Component of the PSA increases with the annual PSA reset in 2/09.
(2) TCA under proposed rates includes impact of moving transmission charge from base rates to TCA
(3) Bill impact excludes regulatory Assessment charge, taxes and fees.
(4) Bill impact excludes adjustors other than the PSA Forward Component

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 11, column 31
Total Company
(Thousands of Dollars)

Proforma Adjustment: **50% of Lobbying Expenses**
Adjustment to include 50% of Lobbying costs in the Test Year pursuant to Decision No. 69663.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Other Electric Revenue	$ -
3.	**Expenses**	
4.	Operations & Maintenance	-
5.	Administrative and General	1,455
6.	Operating Revenues Less Fuel and Purchased Power Expenses	$ (1,455)
7.	**Operating Income (before income tax)**	**$ (1,455)**
8.	Current Income Tax Rate - 39.36%	(573)
9.	**Operating Income After Tax**	**$ (882)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 11, column 32
Total Company
(Thousands of Dollars)

Proforma Adjustment: **SurePay/AutoPay Discount**
Adjustment to Test Year operations to decrease revenue to reflect a $0.48 monthly discount to SurePay/AutoPay customers in accordance with Decision No. 69663.

Line No.	Description	Total Company Amount
1.	**Revenues**	
2.	Operating Revenue	$ (769)
3.	**Expenses**	-
4.	**Operating Income (before income tax)**	**$ (769)**
5.	Current Income Tax Rate - 39.36%	(303)
6.	**Operating Income After Tax**	**$ (466)**

APS

SERVICE SCHEDULE 6
IMPACT FEE

Customers requesting permanent electric service at a location where APS has not previously provided electric service will be required to pay an Impact Fee prior to service energization. The amount of the fee is dependent on the size, phase, and voltage requirements of the customer as shown in the following table:

TABLE 1 Single Phase Service

SES (Amperage)	Fee ($)
60	$400
100	$650
125	$850
150	$1,000
200	$1,300
225	$1,500
300	$2,000
400	$2,650
600	$4,000
800	$5,300

TABLE 2 Three-Phase Service Fees

SES (Amperage)	Three Phase at 120/240 V	Three Phase Service at 120/208 V	Three Phase Service at 277/480 V
60	$1,800	$1,600	$3,600
100	$3,000	$2.600	$6,000
125	$3,750	$3,250	$7,500
150	$4,500	$3,900	$9,000
200	$6,000	$5,200	$12,000
225	$6,800	$5,850	$13,500
300	$9,000	$7,800	$17,900
400	$12,000	$10,400	$24,000
600	$17,900	$15,600	$35,000
800	$24,000	$20,800	$48,000
1000	$30,000	$26,000	$60,000
1200	$36,000	$31,200	$72,000
1600		$41,600	$96,000
2000		$52,000	$120,000
2500		$65,000	$150,000
3000		$78,000	$180,000

The Impact Fee for customers requesting service that are not listed in Tables 1 or 2 will be based on $72 per kVA of estimated connected load as determined by the Company.

APS

ADJUSTMENT SCHEDULE TCA-1
TRANSMISSION COST ADJUSTMENT

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail electric schedules, with the exception of Solar-2. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

Schedule TCA-1 will be adjusted coincident with changes to the Company's Open Access Transmission Tariff (OATT) or any successor transmission tariff, as authorized by the Federal Energy Regulatory Commission (FERC). Changes to the TCA-1 will become effective upon filing with the ACC.

RATE

The charge shall be calculated at the following rate:

Customer Class	March 1, 2008 TCA-1 Charge
Residential	
Network transmission	$0.00516/kWh
Scheduling	$0.000069/kWh
Regulation	$0.000267/kWh
Spinning Reserve	$0.000618/kWh
Operating Reserve	$0.000078/kWh
Total	$0.00619 /kWh
General Service 20 kW or less	
Network transmission	$0.00435/kWh
Scheduling	$0.000056/kWh
Regulation	$0.000217/kWh
Spinning Reserve	$0.000502/kWh
Operating Reserve	$0.000064/kWh
Total	$0.00519 /kWh
General Service over 20kW, under 3,000 kW	
Network transmission	$1.796/kW
Scheduling	$0.0208/kW
Regulation	$0.0813/kW
Spinning Reserve	$0.1879/kW
Operating Reserve	$0.0238/kW
Total	$2.1098 /kW
General Service 3,000 kW or greater	
Network transmission	$1.735/kW
Scheduling	$0.0236/kW
Regulation	$0.0919/kW
Spinning Reserve	$0.2124/kW
Operating Reserve	$0.0269/kW
Total	$2.0898 /kW

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company. All payments received for new or upgraded service under provisions of this schedule shall be non-refundable.

The following policy governs the extension of distribution overhead and underground electric facilities ~~rated up to 21kV~~ to customers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Backbone Infrastructure means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

b. Conduit Only Designs mean a line extension request where the developer is only requesting the conduit layout and design to serve the project. Local distribution facilities such as transformers and services will be installed at a later date when lot sales occur.

c. Corporate Business & Industrial Developments means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use. Separate line extensions and equipment installations may be needed to provide service to each permanent customer.

d. High Rise Residential means residential multi-family developments built with four or more floors, usually using elevators for accessing floors.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

f. Local Facilities means the electrical distribution facilities constructed solely to serve individual customers or groups of customers. For example, the local facilities to serve a Residential Homebuilder Subdivision would consist of the line extension required to tie the subdivision to the APS distribution system as well as the electrical facilities constructed within the subdivision including metering costs. – Projects requiring the relocation or removal of existing facilities will be required to pay the relocation or removal cost in addition to the cost for the Local Facilities.

g. Master Planned Community Developments means developments that consist of a number of separately subdivided parcels for different "Residential Homebuilder Subdivisions". Developments may have a variety of uses including residential, commercial, and public use facilities.

h. Mixed Use Residential Developments means buildings that consist of both residential and commercial use, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

i. Residential Custom Home "Lot Sale" Developments means any tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home. Separate line extensions and equipment installations may be needed to provide service to each permanent customer.

~~DEFINITIONS (cont)~~

j. Residential Homebuilder Subdivisions means any tract of land which has been divided into four or more contiguous lots with an average size of one acre or less in which the developer is responsible for the construction of residential homes or permanent mobile home sites.

k. Residential Multi-family Developments means developments consisting of apartments, condominiums, or townhouse developments.

l. Residential Single Family means a house, or a mobile home permanently affixed to a lot or site.

m. System Facilities means those facilities installed by the Company such as new substations, new feeder lines and/or upgrades, and other equipment installations required to support the Company's aggregated load serving and voltage regulation requirements as a result of new growth.

1.0 RESIDENTIAL

1.1 SINGLE FAMILY HOMES

Residential extensions will be made to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as less than four homes. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. System Facilities costs will be based on the size and voltage of the service entrance section for which service is being provided by the Company. Payment is due at the time the extension agreement is executed.

1.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

Extensions will be made to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant(s) signs an extension agreement. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. The cost of Local Facilities will be estimated based on average cost per lot. System Facilities costs will be based on the size and voltage of the service entrance section for which service is being provided by the Company. Payment is due at the time the extension agreement is executed.

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

1.3.1 Extensions will be made to residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. System Facilities costs will be based on the size and voltage of the service entrance section for which service is being provided by the Company.

1.3.2 Payment is due at the time the extension agreement is executed.

1.3.3 Line extensions and/or equipment installations will be made for each permanent customer upon request for service in accordance with Section 1.1 of this service schedule.

1.3.4 Company will provide "conduit only" designs provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required.

1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

1.4.1 Extensions will be made to Master Planned Community Developments in advance of application for service by permanent customers, provided the applicant signs an extension agreement. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. System Facilities costs will be based on the size and voltage of the service entrance section for which service is being provided by the Company. Payment is due at the time the extension agreement is executed.

1.4.2 Line extensions and equipment installations will be made for each residential subdivision within the planned development in advance of application for service by permanent customers in accordance with Section 1.2 of this Service Schedule.

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

Extensions will be made to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. System Facilities costs will be based on the size and voltage of the service entrance section for which service is being provided by the Company. Payment is due at the time the extension agreement is executed.

1.6 HIGH RISE AND MIXED USE RESIDENTIAL DEVELOPMENTS

1.6.1 Extensions will be made to High Rise and Mixed Use Residential Developments where the residential units are privately owned and either individually metered or master metered in accordance with Section 5.11.

1.6.2 In general, APS will provide service to these type of developments at one point of delivery and it is the applicant's responsibility to provide and maintain the electrical distribution facilities within the building.

1.6.3 Extensions will be made to High Rise and Mixed Use Residential Developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. Payment is due at the

time the extension agreement is executed.

2.0 NON-RESIDENTIAL

General Sservice line extensions and equipment installations will be made to all applicants not meeting the definition of Residential or as provided for in Section 2.1, or Section 3.0 of this Schedule. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. System Facilities costs will be based on the size and voltage of the service entrance section for which service is being provided by the Company.Payment is due at the time the extension agreement is executed.

2.1 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.1.1 Extensions will be made to Corporate Business & Industrial Park Developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. Payment is due at the time the extension agreement is executed.

2.1.2 Extensions will be made to individual customers within the Corporate and Business Park Development in accordance with the applicable sections of this Service Schedule.

3.0 OTHER CONDITIONS

3.1 IRRIGATION CUSTOMERS

Extensions will be made to Irrigation Customers provided the applicant signs an extension agreement. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. System Facilities costs will be based on the size and voltage of the service entrance section for which service is being provided by the Company. Payment is due at the time the extension agreement is executed. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the applicant~~customer~~, the applicant~~customer~~ shall make a payment in advance of installation or construction equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

3.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to pay the total estimated construction cost.

4.0 UNDERGROUND CONSTRUCTION

4.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

4.1.1 The extension meets all requirements as specified in Sections 1.0, 2.0, or 3.0.

4.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

4.1.3 The customer or applicant(s) provides installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications.

4.1.4 In lieu of customer or applicant(s) providing these services and equipment, the company may provide and the customer or applicant(s) will make a payment equal to the cost of such work plus any administrative or inspection fees incurred by Company. Customers or applicants electing this option will be required to sign an agreement indemnifying and holding APS harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than APS' contractors, which Claims arise out of the trenching and conduit placement, provided the claims are not attributable to APS' gross negligence or intentional misconduct.

5.0 GENERAL CONDITIONS

5.1 VOLTAGE

All extensions will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department, applicant will be required to pay the costs of any required studies.

5.2 POINT OF DELIVERY

5.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus riser.

5.2.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

5.2.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, APS and customer shall mutually agree upon the designated point of delivery.

5.3 THREE PHASE

Extensions for three-phase service can be made under this extension policy where the customer has installed major three-phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVA demand shall qualify for three phase service.

5.4 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by customer or developer.

5.6 OWNERSHIP

Except for customer-owned facilities, all electric facilities installed in accordance with this Service Schedule will be owned, operated and maintained by Company.

5.7 MEASUREMENT AND LOCATION

5.7.1 Measurement must be along the proposed route of construction.

5.7.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

5.7.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

5.8 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

5.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads

of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the customer will be included in the payment described in previous sections of this Service Schedule.

5.10 RELOCATIONS AND/OR CONVERSIONS

5.10.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics. The estimated cost of relocation or conversion as determined by the Company will be included in the payment described in previous sections of this Service Schedule.

5.10.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make payment equal to the total cost of relocation.

5.11 MASTER METERING

5.11.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

5.11.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Corporation Commission's Rules and Regulations or the requirements discussed in 5.11.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

5.11.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

5.11.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

5.11.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

5.11.4 Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a payment equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on the basis specified in Section 1. Applicant is responsible for all costs related to the installation of new service entrance equipment.

5.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 1.0, 2.0 or 3.0.

5.13 STUDY AND DESIGN PAYMENT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company an amount equal to the estimated cost of preparation. ~~Where the applicant authorizes Company to proceed with construction of the extension, the payment shall be credited to the cost of the extension otherwise the payment shall be nonrefundable.~~ Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

5.14 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

5.15 EXTENSION AGREEMENTS

All line extensions or equipment upgrades requiring payment by the customer shall be in writing and signed by both the customer and Company.

5.16 ADDITIONAL PRIMARY FEED

When specifically requested by the customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the request's feasibility and the customer may be required to pay for the added cost as well as the applicable rate for the additional feed requested.

5.17 POLICY EXCEPTION

The Schedule 3 as stated herein is applicable to all customers unless specific exemptions are approved by the Arizona Corporation Commission. The following exemptions have been approved:

5.17.1 Residential Homes on Native American Land

Extensions for residential homes on Native American Reservations will be made in accordance with the provisions of Service Schedule 3 that was in effect April 1, 2005 through June 30~~1~~, 2007. Application of this Section 5.17.1 is limited to Native American Reservations as defined by applicable Federal law.

5.17.2 Existing Line Extension Agreements

All applicants who have executed line extension agreements as of February 27, 2008 will be "grandfathered" into the Schedule 3 in effect at the time the agreement was executed.

5.17.3 Transition Plan

Applicants that have not executed a line extension agreement will be provided extensions in accordance with the provisions of Service Schedule 3 that was in effect July 1, 2007 through February 26, 2008, if they meet both of the following conditions:

1. Such applicant has received from APS, within six months prior to February 27, 2008, a written estimate of the costs to the applicant for extending service (i.e. received an estimate during the period August 27, 2007 and February 27, 2008); and

2. That same applicant executes a written line extension agreement within twelve (12) months of February 27, 2008 (i.e. no later than February 27, 2009).

David K. Pickles

DIRECT TESTIMONY OF DAVID K. PICKLES

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

Table of Contents

I. Introduction 1

II. Summary of Testimony 1

III. Summary of The Benefits and Opportunities for DSM 2

IV. Historical Ratemaking and Underinvestment in DSM 7

V. Overview of Progressive Ratemaking Mechanisms for DSM 12

VI. APS's Current Mechanisms 19

VII. Implications for Future Mechanisms and Additional Programs 21

Qualifications ..... Appendix A

DIRECT TESTIMONY OF DAVID K. PICKLES
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. David K. Pickles, 7160 North Dallas Parkway, Suite 340, Plano, Texas 75024.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by ICF International (ICF) as the Southern Region Vice President for the Energy Efficiency Practice. Founded in 1969, ICF's more than 2,500 employees provide government and commercial clients with consulting services and technology solutions in the energy, climate change, environment, transportation, social program, health, defense, and emergency management markets.

My responsibilities include the general oversight and delivery of ICF's energy efficiency projects throughout the southern United States. In this role, I supervise the implementation of numerous energy efficiency programs for utilities, oversee the development of Demand-Side Management (DSM) potential studies, design DSM programs, support states in developing legislative and regulatory policy concerning energy efficiency, develop integrated resource plans, and provide related consulting services.

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. My qualifications are set forth in Appendix A to my testimony.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony provides an overview of issues related to APS's ongoing investment in DSM programs. Specifically, my testimony provides:

- **Section III**. A summary of the benefits of typical DSM programs, and a discussion of the potential opportunity for significant additional investment in cost-effective DSM by APS.

- **Section IV**. A discussion of the lack of investment in DSM nationally that has resulted from historical ratemaking practices when applied to DSM programs, and a validation of the need for more progressive ratemaking practices provided by several national and industry associations including the National Association of Regulatory Utility Commissioners (NARUC), the National Action Plan for Energy Efficiency (NAPEE), and regulatory commissions nationwide.

- **Section V**. An overview of the progressive ratemaking mechanisms that have been adopted by regulators in many states, including: recovery of program costs, treatment of the under-recovery of fixed costs (*i.e.*, lost margins), and mitigation of other disincentives to invest in DSM resources instead of supply-side resources (*i.e.*, incentives).

- **Section VI**. A discussion of the current mechanisms authorized for use by APS, and a conclusion that the currently-approved mechanisms effectively limit further investment by APS in additional cost-effective DSM programs and are not on par with the ratemaking mechanisms approved by leading states in the area of DSM.

- **Section VII**. A discussion of APS's desire to invest additional resources in DSM, and its specific recommendation for more progressive ratemaking mechanisms.

III. SUMMARY OF THE BENEFITS AND OPPORTUNITIES FOR DSM

Q. WHAT IS DEMAND-SIDE MANAGEMENT?

A. DSM can be broadly defined as the set of actions that can be taken to influence the level and timing of the consumption of electricity. There are two common subsets of DSM: 1) energy efficiency and 2) demand response.

Energy efficiency typically includes actions designed to increase efficiency by maintaining the same level of production or comfort, but using less energy input. For example, a program designed to encourage commercial customers to retrofit their buildings with more efficient lighting systems would typically be referred to as an "energy efficiency" program. Other programs that could fit into this category might include those designed to improve the quality of the installation of air-conditioners, to improve maintenance and operations procedures for large pieces of equipment, and to promote the construction of new homes that use less energy than homes built using standard construction practices. In general, energy efficiency programs provide a reduction in the overall quantity of electricity consumed over the year, but may not necessarily reduce the electricity demanded at the hour of system peak (for APS, this is typically on a hot summer afternoon around 4-6 p.m.).

In contrast, a demand response program typically includes actions specifically designed to encourage customers to reduce usage during peak times (or to shift that usage to other times). For example, a program that provides a payment to customers who permit the utility to cycle off their air-conditioners for brief periods using a remote switch could be classified as a demand response program. Other programs that might fall into this category include those that provide time-differentiated rate designs or critical peak price signals which encourage reduction of consumption during peak times, and interruptible rate programs which provide incentives to customers who reduce demand when called upon. In general, demand response programs provide a reduction in the electricity demanded at the time of system peak and may or may not reduce total annual electricity usage.

APS's currently approved DSM programs, the costs of these programs, and the estimated impacts of these programs on system peak and annual consumption are provided in Table 1. These programs, by direction of the ACC, are focused on reducing annual energy consumption and are therefore considered energy efficiency programs, even though they also result in some reduction of APS system peak.

Table 1. Summary of APS's Currently Approved DSM Programs

DSM Program Summary
Program-to-Date
January 2005 - December 2007

DSM Program	Capacity Savings MW	Lifetime[1] MWh Savings	Program Cost
Residential			
Low Income	0.3	36,603	$ 2,546,901
Existing Homes HVAC	7.1	260,365	$ 3,539,867
New Home Construction	2.9	134,832	$ 2,456,690
Consumer Products	42.1	1,467,359	$ 6,784,101
Totals for Residential	**52.4**	**1,899,159**	**$ 15,327,559**
Non-Residential			
Large Existing Facilities	8.9	1,003,888	$ 7,384,886
Large New Construction	1.7	257,424	$ 2,852,733
Small Business	0.5	42,577	$ 1,434,035
Building Operator Training	0.1	8,962	$ 88,154
Energy Information Services	0.0	-	$ 70,379
Schools	0.6	63,602	$ 687,045
Total for Non-Residential	**11.8**	**1,376,453**	**$ 12,517,232**
Subtotal Residential & Non-Res.	**64.2**	**3,275,612**	**$ 27,844,791**
Measurement, Evaluation & Research	-	-	$ 2,072,285
Performance Incentive	-	-	$ 3,323,736
TOTAL	**64.2**	**3,275,612**	**$ 33,240,812**

1. Refers to savings over the expected lifetime of each program measure.

Q. WHAT ARE THE BENEFITS OF DSM?

A. In broad terms, DSM programs have the potential to provide the end-use

services that customers desire (*e.g.*, lighting, cooling, etc.) at a lower cost than the utility would otherwise incur to build the generation, transmission, and distribution facilities necessary to provide that end-use service with electricity.

Certain DSM programs may also have additional benefits, including:

- Reduced environmental impacts, including: lower emissions from power plants when electricity consumption is reduced, lower land and water use impacts as new plant construction is deferred, and reduced exposure to potential future regulation of the carbon emitted from generating plants;
- Increased local economic activity as customers use the money saved on their electricity bills to purchase local goods and services;
- Improved energy security, as reliance on fossil fuels (and their inherent volatility and exposure to world markets) is reduced;
- More efficient use of existing generation, transmission, and distribution facilities as loads are "leveled" over the year;
- Increased customer satisfaction;
- Increased flexibility and modularity in the planning of the utility system since DSM programs provide additional and potentially more scalable ways to meet future demand growth, and do so in smaller increments than many supply-side investments; and
- Increased local economic development as the expenditures made by APS on incentives, marketing, training, and other activities flow to local trade allies.

Of course, not all DSM programs exhibit all these benefits, and such benefits must be carefully evaluated in the context of the drawbacks that may be associated with individual DSM programs. These drawbacks might include potential adverse short term increases in rates, uncertainty surrounding the persistence and measurement of the impacts of the programs, difficulty in

forecasting the participation and costs in the programs, diminishing economies of scale as DSM programs approach their maximum size, equity between customers, and the impact on the system if utilities rely upon DSM programs that ultimately do not yield the intended impact.

Despite these potential drawbacks, it is clear that DSM programs have an important role to play in any utility's mix of resources available to meet increases in the demand for electricity. This is especially true in today's environment of increasing prices for generating fuels, increasing environmental concerns and regulations, shrinking generating capacity reserve margins and their potential adverse impacts on system reliability, and concerns over the energy independence of the United States.

Q. DO YOU BELIEVE THAT THERE IS AN OPPORTUNITY FOR ADDITIONAL COST-EFFECTIVE DSM PROGRAMS WITHIN THE APS SERVICE TERRITORY?

A. While APS's current programs provide an appropriate foundation given current ratemaking mechanisms, I believe additional cost-effective programs are possible - contingent upon the approval of improved ratemaking mechanisms as discussed later in my testimony.

APS completed a high-level assessment of the potential for DSM programs (filed on September 12, 2007 in Docket No. E-01345A-05-0182) and has concluded that the cost-effective potential for DSM programs is in the range of 2,600 to 3,900 GWh by 2020, given a reasonable set of assumptions regarding incentive levels and customer acceptance. APS believes that approval of improved ratemaking mechanisms will enable it to further refine this estimate of

additional potential and develop specific proposals for new or expanded programs for implementation.

IV. HISTORICAL RATEMAKING AND UNDERINVESTMENT IN DSM

Q. HAVE HISTORICAL RATEMAKING MECHANISMS BEEN EFFECTIVE IN ELICITING APPROPRIATE LEVELS OF DSM?

A. No. In general, the historical treatment of DSM programs nationally has failed to address three key limitations on the ability of a prudent utility to offer comprehensive DSM programs. These three key limitations are:

a. **Recovery of the contribution to fixed costs (lost margins).** Past cost recovery mechanisms often failed to recognize the fact that most utility rates are designed to recover some portion of the fixed costs of providing utility service on a variable (per kWh or per kW) basis. That is, the rate the customer pays for each kWh includes both a variable fuel cost component and a fixed cost component. When a DSM program reduces a customer's consumption, the utility may save the variable fuel cost, but does not see a decline in its fixed costs in the short term. The revenue decline that the utility experiences due to the DSM program includes not only the decline in fuel cost, but also in the fixed cost contribution. Absent some alternative way to recover this lost fixed cost contribution (sometimes referred to as either partial or full decoupling), the utility's implementation of DSM programs will directly reduce its earnings.

b. **Recovery of program costs**. Under historical mechanisms, recovery of program costs was typically achieved retrospectively (after the utility had spent the money), either in a rate case or through a special rider designed to adjust rates without a rate case. Often, this failed to compensate the utility for the time-value of money and the use of its capital, and exposed the utility to risk of non-recovery with changes in regulatory requirements. Further, it did not keep up with the often increasing amount of DSM budgets as programs grew in size and effectiveness. The utility was always behind in its compensation for the programs it provided.

c. **Financial Performance**. The more a utility invests in generation, transmission, and distribution equipment, the larger the dollar value of its rate base. Since the utility is given the opportunity to earn a rate of return (expressed as a percent) on this rate base, as the rate base grows, the

> utlity's earnings grow as well. To the extent that DSM displaces future investment in generation, transmission, and distribution but does not provide a similar return (all else being equal) the utility's earnings will be lower than they otherwise would have been. Absent some mechanism to meaningfully offset these effects and show adequate earnings growth, the utility will have little incentive to invest in DSM.

These limitations, and the progressive ratemaking mechanisms that have been adopted by utility regulators in many states, are discussed in additional detail later in my testimony.

As a result of these limitations, states that have not adopted progressive mechanisms have typically seen much lower investment in DSM programs. This can be demonstrated both anecdotally (consider that many of the states that make the largest investment in DSM address most or all of these limitations) and empirically. A recent paper using data from 200 electric utilities over 15 years showed with very high statistical confidence that:

> "regulators who add incentives would expect greater energy savings and more utility spending for energy efficiency. This paper demonstrates that regulators should give serious consideration to decoupling and/or direct financial incentives to utilities as the best approaches to start, expand, and sustain utility-sponsored energy efficiency programs."[1]

The paper also concludes that:

> "When there is more at stake, as today, regulators should not simply cause utilities to spend more on energy efficiency and seek a "just and reasonable" means to recover the costs. Instead, regulators should find out what forms of regulation cause utilities to succeed and sustain utility sponsored energy efficiency over the long-term."

---

[1] Energy Efficiency: Do Regulatory Incentives Matter? Charles J. Cicchetti and James H. Lin. Submitted for Peer Review, 2008. Dr. Ciccetti is the former Jeffrey J. Miller Chair in Government, Business and the Economy at the University of Southern California and was previously Chair of the Wisconsin Public Service Commission.

Q. HAVE THESE LIMITATIONS BEEN RECOGNIZED NATIONALLY?

A. Yes. Many state regulators and other organizations have recognized the need to address these limitations on previous DSM recovery mechanisms. For example, NARUC adopted a resolution urging its member state commissions to:

1. consider the loss of earnings potential connected with the use of demand-side resources,

2. adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively, and

3. "otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action."[2] (Emphasis added.)

Similarly, the National Action Plan for Energy Efficiency[3] (Action Plan) provides a "call to action to utilities, state utility regulators, consumer advocates, consumers, businesses, other state officials, and other stakeholders to create an aggressive, sustainable national commitment to energy efficiency. The Action Plan offers the following recommendations as ways to overcome barriers that have limited greater investment in energy efficiency for customers of electric and gas utilities in many parts of the country. The following recommendations are based on the policies, practices, and efforts of leading organizations across the country. For each recommendation, a number of options are available to be pursued based on regional, state, and utility circumstances:

- Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective; and

[2] NARUC Resolution in Support of Incentives for Electric Utility Least-Cost Planning (7/27/1989).

[3] The National Action Plan for Energy Efficiency (Action Plan) presents policy recommendations for creating a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations. The Action Plan was developed by more than 50 leading organizations representing key stakeholder perspectives, including regulators, environmental groups, utilities, state and federal agencies, and end-users.

- Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments."

As noted by a report developed by the Action Plan which focuses on these issues:[4]

> "How these impacts are addressed creates the incentives and disincentives for utilities to pursue energy efficiency investment. The relative importance of each of these (cost recovery, lost margins, and shareholder incentives) depends on the specific context—the impacts of energy efficiency programs will look different to gas and electric utilities, and to investor-owned, publicly owned, and cooperatively owned utilities. Comprehensive policies addressing all three levels of impact generally are considered more effective in spurring utilities to pursue efficiency aggressively. Ultimately, however, it is the cumulative net effect on utility earnings or net income of a policy that will determine the alignment of utility financial interests with energy efficiency investment." (Emphasis added).

Q. HOW HAVE INDIVIDUAL STATES ADDRESSED THESE ISSUES?

A. States have taken a variety of approaches based on their own unique circumstances, as summarized in Table 2.[5] As suggested by Table 2, incentives are very common with 18 of the 51 jurisdictions offering utility shareholder incentives of some kind. Six states provide a separate mechanism for the recovery of lost margins (identified as a Lost Revenue Adjustment Mechanism or "LRAM" in Table 2), and 14 states have either approved or have pending electric decoupling mechanisms to insulate utility earnings from the lost margins

---

[4] Aligning Utility Incentives with Investment in Energy Efficiency. November 2007.

[5] Action Plan citing *Kushler et al.*, 2006. (Current as of September 2007.) System Benefit Funds are typically a rider recovered through utility rates and used for DSM programs, but the programs may or may not be administered by the utility.

attributable to DSM program performance. Further, many of the leading states have combined utility incentives with both timely recovery of costs and of lost margins. Twelve states have either an approved or pending mechanism treating both lost margins and shareholder incentives.

Table 2. Status of Electric Efficiency Cost Recovery and Incentive Mechanisms

State	Method of Cost Recovery			Fixed Cost Recovery		Incentives
	Rate Case	System Benefit Charge	Adjustment Clause	Decoupling	LRAM	
Alabama	●					
Alaska						
Arizona	●	●	●			●
Arkansas						
California	●	●		●		●
Colorado	●		●	○		●
Connecticut		●			●	●
D.C.	●			○		
Delaware	●			○		
Florida			●			
Georgia	●					●
Hawaii				○		●
Idaho	●			●		
Illinois	●					
Indiana	●				●	●
Iowa	●		●			
Kansas						●
Kentucky			●		●	●
Louisiana						
Maine		●				
Maryland				○		
Massachusetts		●		○	●	●
Michigan						
Minnesota	●			●		●
Mississippi	●					
Missouri						
Montana		●				●
Nebraska						
Nevada	●					●
New Hampshire		●		○		●
New Jersey		●		○		
New Mexico	●					

State	Method of Cost Recovery			Fixed Cost Recovery		Incentives
	Rate Case	System Benefit Charge	Adjustment Clause	Decoupling	LRAM	
New York		●		●		
North Carolina						
North Dakota						
Ohio			●		●	●
Oklahoma						
Oregon		●				
Pennsylvania	●					
Rhode Island		●		●		●
South Carolina						●
South Dakota						
Tennessee						
Texas	●					
Utah	●		●			
Vermont		●			●	●
Virginia						
Washington	●		●			
West Virginia						
Wisconsin	●	●		○		
Wyoming						

● = *Approved* ○ = *Pending*

V. OVERVIEW OF PROGRESSIVE RATEMAKING MECHANISMS FOR DSM

Q. PLEASE PROVIDE AN OVERVIEW OF MECHANISMS FOR THE RECOVERY OF DSM PROGRAM COSTS.

A. Cost recovery is usually achieved in two ways:

- Through a rate case, wherein a "normal and representative" level of DSM expenditure is set and treated either as an expense item (designed to be fully recovered over a one year period and where a $1 expenditure on a program would increase the annual revenue requirement by $1) or, more rarely, treated as a capital item (in which the expenditure is amortized over a period of several years, a rate of return is allowed on the unamortized balance, and where the $1 expenditure in Year 1 may, for example, be recovered as a $0.24/year over 5 years including the rate of return). In either case, an appropriate annual increase in revenues is developed and allocated over representative sales volumes. The appropriate level of recovery is not revisited until the utility's next general rate case, and there is no attempt made to ensure that actual recoveries tie precisely to actual expenses. This represents the

"historical" rate case mechanism, and does a poor job of tracking fluctuations in DSM budgets, participation, and sales levels; or

- Through an adjustor clause, wherein the utility makes a periodic filing (typically annually) to adjust the recovery amount to reflect expenditures on the DSM programs. The mechanism can be designed to recover either actual program costs in the previous year(s), or forecast program costs, and typically includes any reconciliations that may be necessary due to anticipated sales volumes being different from actual sales volumes in the previous period. In general, if the recovery is based on historical costs, the utility is also permitted to recover carrying charges for the period between the incurrence of the cost and the time of recovery at a rate equal to the utility's cost of capital. As with rate case recovery, it is also possible to treat the costs as capital items and amortize them over a number of years.

The selection of an appropriate mechanism for recovery of DSM program costs is influenced by several factors, including: 1) the stability of the DSM expenditures, 2) the timing of recovery, 3) the perceived risk of non-recovery, 4) the potential for higher short term rate impacts, and 5) the overall cost to customers of the recovery.

As a practical matter (especially in jurisdictions where DSM programs are comparatively new), DSM program budgets tend to be unstable and increase significantly from year to year as new programs are developed, as the utility becomes more proficient in the design and delivery of programs, and as customers and regulators become more interested in DSM programs. This effect is magnified during periods of rising fuel and generation costs, which tend to improve the cost-effectiveness of DSM measures and therefore justify the introduction of additional programs.

As DSM budgets grow larger and become more meaningful in the context of the utility's earnings, it is appropriate to permit more timely and predictable

recovery of prudently incurred DSM program costs as both a matter of equity and as a signal to the utility and its shareholders that DSM is preferred relative to supply side investments.

The timing of recovery is important both due to regulatory principles that suggest that the recovery of program costs should, where possible, be matched with the time period when the costs were incurred (ensuring that, in general, those customers who benefit from the opportunity to participate in the DSM programs are those that bear the costs of the programs) and due to a desire to minimize the utility's costs of carrying unrecovered amounts on its books for an extended period of time and any resultant negative impacts on cash flow. Further, the longer a utility carries the costs of an asset on its books, the greater the utility's exposure to changes in regulatory policy that may jeopardize recovery of those costs. This is especially true of DSM or "regulatory assets" where there is no physical asset to be secured (such as a power plant) but instead a regulatory compact to recover a specified amount in the future.

Expensing (versus capitalizing) the program costs has the advantage of being the simplest method to administer and of having the lowest cost to ratepayers (since it does not include a rate of return for the utility, other than any carrying charges that may be earned if the recovery is not made concurrent with the costs). However, it may also lead to higher short term rate increases as costs are recovered in a single year instead of being spread out over multiple years.

In many states that have made a significant commitment to DSM, an adjustment clause is used or the utility is subject to frequent sometimes effectively annual rate cases or other mechanisms that have a similar impact. This has the effect of allowing significant increases in program funding without penalizing the utility

and of matching actual recoveries with actual expenditures. Further, most states have chosen to expense (rather than capitalize) the DSM program costs due to its relative simplicity, lower overall cost, typically acceptable rate impacts, and lower perceived risk to the utility.

Q. PLEASE PROVIDE AN OVERVIEW OF MECHANISMS FOR THE TREATMENT OF LOST NET MARGINS.

A. As noted previously, DSM programs directly reduce future sales, and thereby reduce future utility earnings by the amount of net margin that would have been associated with those sales. While the ultimate impact of the "lost margins" is a function of the time between utility rate cases (the more frequent the rate cases, the shorter the period of time that the utility is subject to lost margins before it can adjust its overall rates to make up the difference), the nature of the "test year" used (*e.g.*, historical versus future), the average margins in the rate classes where the DSM programs are offered, and other factors, it is clear that these lost margins can be very significant. For example, the Regulatory Assistance Project[6] has estimated that for a typical vertically integrated utility a 1% drop in sales translates to a 5% drop in profits, and that for a typical transmission and distribution utility the same 1% drop in sales leads to an 11% drop in profits.

Absent a mechanism which reduces or eliminates the sensitivity of the utility's earnings to the impacts of DSM programs, many utilities have chosen to minimize spending on DSM (up to the point they fear a regulatory or legislative penalty that is more punitive than the lost margins.) While the threat of

---

[6] "Understanding the Ratemaking Implications of Linking Profits and Sales," presentation to the NARUC Workshop: Aligning Regulatory Incentives with Demand-Side Resources, August 2, 2006 by David Moskovitz. The Regulatory Assistance Project (RAP) is a non-profit organization, formed in 1992 by experienced utility regulators, that provides research, analysis, and educational assistance to public officials on electric utility regulation.

penalties is one of the tools that regulators always have available, it is my experience as both an ex-regulator and a former utility executive that mechanisms that align the interests of regulators, customers, and utility shareholders are much more likely to be sustainable and to provide the desired results (including a large long-standing commitment to DSM) than is the threat of penalties.

Two primary approaches have been developed to address the issue of lost margins: 1) lost revenue adjustment mechanisms, and 2) decoupling.

Q. PLEASE DESCRIBE DECOUPLING IN MORE DETAIL.

A. The term "decoupling" is used to describe a variety of ratemaking methods that sever the link between utility sales volumes and margins. Decoupling is typically achieved by establishing (typically in a rate case or other special purpose proceeding) the total revenue per customer or per unit of sales that can be collected by the utility in each year. Any over/under collections are subtracted/added to the following year's allowed revenue.

Q. PLEASE DESCRIBE LOST REVENUE ADJUSTMENT MECHANISMS IN MORE DETAIL.

A. Lost Revenue Adjustment Mechanisms (LRAMs) differ from decoupling in that they only recover the lost margins that are induced by the DSM programs. The utility earnings remain sensitive to weather and other sales fluctuations. In simple application, the LRAM is established by:

- Estimating the net margin component of rates per kWh or kW (*i.e.*, the difference between the full retail rate and the utility's variable costs), typically by rate schedule or customer type and based on the utility's most recent rate case;
- Establishing the impacts (sales reductions) induced by the DSM

programs;

- Multiplying the net margin component in each rate class by the DSM sales reductions in that class, and
- Using an annual adjustment clause to adjust rates to each customer class to recover those amounts, including any over or under recoveries from previous periods and appropriate carrying charges.

While the LRAM effectively removes the lost margin disincentive associated with DSM programs, it has been criticized by some observers for not completely eliminating all incentives that utilities may have to promote sales. However, it is less likely to have some of the broader drawbacks associated with full decoupling.

Q. PLEASE DESCRIBE UTILITY INCENTIVE MECHANISMS IN MORE DETAIL.

A. Even where timely recovery of DSM program costs and recovery of lost margins are permitted (and especially where they are not), the utility is still not financially indifferent between supply-side and demand-side investments. And, contrary to the NARUC resolution encouraging its member commissions to "ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action," a utility may arguably still have the internal financial incentive to choose supply-side investments over DSM. Recognizing this, many jurisdictions have developed shareholder incentive mechanisms designed to offset this disparity. These incentives generally fall into one of three separate categories:

- Shared Savings – where the utility is eligible to earn a share of the DSM program's net benefits, typically the value of avoided capacity and energy saved less the program costs. For example, utilities in Minnesota can earn a share of the program's net benefits up to a maximum incentive equivalent to 30% of total

program expenditures;

- Performance Target – where the utility is eligible to earn an incentive for meeting pre-specified goals. For example, utilities in Connecticut are eligible to earn an incentive equivalent to up to 8% of program expenditures based on goals achieved; and

- Rate of Return – where utilities that capitalize their DSM program expenditures can earn a premium rate of return on their investment. For example, utilities in Nevada can increase their return on equity for DSM programs 5 percentage points relative to the return on equity for supply-side investments.

Each of these incentives has its own set of advantages and disadvantages, and none has been identified as being appropriate in all cases. As noted earlier, the kind of incentive mechanism, and the amount of incremental earnings opportunity it should afford the utility, has to be viewed in the context of the cost recovery and lost margin treatments, as well as the cost-effectiveness of the programs, the ease of achieving program goals, and other factors. However, the existence of a significant incentive has been shown to be very influential in garnering utility support for DSM programs. And although incentives typically require additional resources to accurately evaluate program impacts, they are widely held to be an important tool for regulators in setting policy and guiding utility behavior.

Q. ARE THERE ANY OTHER MORE INNOVATIVE RATEMAKING MECHANISMS CURRENTLY RECEIVING INDUSTRY REVIEW?

A. Yes. Duke Energy has proposed a mechanism called "Save-a-Watt" (otherwise known as the "virtual power plant" approach) in the jurisdictions where it serves. While this mechanism has not yet been approved, it does identify an alternate way of treating cost recovery, lost margins, and shareholder incentives.

Q. PLEASE DESCRIBE HOW SAVE-A-WATT (SAW) WOULD OPERATE.

A. Instead of providing explicit recovery of costs, lost margins, and a shareholder incentive, the SAW approach preserves utility earnings relative to alternate supply-side investments by simply permitting the utility to recover 90% of the costs avoided by the DSM programs. The recovery amount would be insensitive to the costs of the programs, but highly sensitive to the results of the programs.

For example, if the avoided costs of the program equate to $50/MWh, Duke would receive a payment of $45/MWh saved (90% of $50). If Duke could implement the programs at an average cost of $41/MWh, it stands to earn a margin of $4/MWh saved. Conversely, Duke bears the risk of the programs failing to achieve expected scale and of being more expensive than estimated. If the programs cost $48/MWh, Duke would stand to lose $3/MWh.

Duke has proposed that SAW be implemented through a balancing mechanism that would permit annual adjustments to avoided cost estimates, evaluate the actual load reduction achieved in the previous year, and determine the appropriate recovery amount by customer class. This recovery amount would then be spread over sales in that customer class, including appropriate adjustments for any over or under recovery in previous periods.

VI. APS'S CURRENT MECHANISMS

Q. PLEASE SUMMARIZE APS'S CURRENT MECHANISMS.

A. APS's DSM program costs are currently recovered through a combination of base rates and a rider that annually adjusts rates retrospectively to recover actual DSM program expenditures in the previous year. APS is also eligible to earn an

incentive based on a sharing of the net benefit of the DSM programs. However, this incentive is capped at 10% of the annual program expenditure. No recovery of lost margins is permitted outside of a general rate case.

Q. WHAT IS YOUR ASSESSMENT OF THE CURRENT APS MECHANISMS?

A. While the mechanisms begin to address some of the previously identified disincentives for DSM, they are not, as a package, sufficient to put DSM on a level playing field with supply-side investments, and they do not provide internal incentives for APS to pursue all cost-effective DSM.

Q. WHAT IS THE PRIMARY SHORTCOMING OF THE CURRENT MECHANISMS?

A. The primary shortcoming is that, as a package, the mechanisms do not provide APS the opportunity to earn a predictable return on its DSM investments that compares with the return it would otherwise earn without the DSM programs. Specifically, the cap on the shareholder incentive at 10% of program expenditures (and the lack of a return on the DSM investments and recovery of lost margins) prevents the incentive from ever offsetting:

- The lost net margins induced by the DSM programs,
- The time value of money associated with funding the DSM programs,
- The opportunity cost of otherwise investing those funds in capital projects,
- The earnings that would otherwise accrue if investments were made in supply-side options, and
- The risk associated with implementing the programs.

VII. IMPLICATIONS FOR FUTURE MECHANISMS AND ADDITIONAL PROGRAMS

Q. IS IT YOUR OPINION THAT APPROVAL OF IMPROVED MECHANISMS WOULD PERMIT APS TO MAKE SIGNIFICANT ADDITIONAL INVESTMENTS IN COST-EFFECTIVE DSM?

A. Yes. APS believes strongly in the benefits of DSM and has the access to capital, customer relationships, usage data, technical expertise, back-office infrastructure, and other capabilities necessary to prudently invest in DSM. Under the oversight of the Commission, APS is in a unique position to ensure that the benefits of DSM are realized through avoided capacity and energy production, and to otherwise coordinate the development of DSM with future transmission needs, environmental regulations, regional load forecasts, and other considerations.

Improved mechanisms are critical if additional DSM programs are to be implemented. Based on its recent DSM market potential study, APS believes that future DSM impacts may be significant. APS will prepare detailed estimates of the impacts of future DSM programs upon action on this item.

Q. HAS APS DEVELOPED A PROPOSAL FOR A SPECIFIC SET OF RECOMMENDED MECHANISMS?

A. Yes. In order reduce the disincentive for APS to increase its spending on DSM programs, APS requests that:

- APS collect otherwise unrecovered fixed costs due to implemented DSM programs based on the MWh impacts in the previous year, priced at the average retail rate less average variable costs for fuel and purchased power. These lost fixed cost contributions should include the impacts of all DSM programs implemented since the last rate case but still within the life of the DSM measures. This amount should be recovered over the anticipated MWh sales volumes in the following year, with a true up to actual sales and recovery amounts in the next adjustment to the Company's Demand Side Management Adjustment Clause (DSMAC).

- APS be permitted to earn an increased performance incentive by removing the existing cap on APS's incentives (currently set at 10% of program expenditures). APS proposes to retain the current sharing relationship between ratepayers (who receive 90% of the net benefits of the programs) and shareholders (who receive 10%).

- APS recover program costs in the same year that they are spent through the Company's DSMAC. This amount should be based on projected DSM spending for both approved and pending programs, with a true-up to actual spending and recoveries in the following year.

All cost recovery and performance incentive amounts above $10 million annually (the amount currently reflected in approved base rates) would be collected through the Company's DSMAC. The testimony of APS witness Gregory DeLizio provides additional details regarding the specifics of these recommended mechanisms.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

APPENDIX A. QUALIFICATIONS

David Pickles **ICF International**
Vice President

EDUCATION

Master of Science Degree in Regulatory Economics, University of Wyoming, Laramie, Wyoming, 1988; Bachelor of Science Degree in Economics, University of Wyoming, Laramie, Wyoming, 1986

EXPERIENCE OVERVIEW

Mr. Pickles serves as ICF's Southern Region Vice President for the Energy Efficiency Practice, where he is responsible for all region activities including project execution, business development, and management. Mr. Pickles has twenty years experience as a regulator, utility senior executive, and industry consultant focused on energy efficiency. Experienced with energy efficiency program design and management, product assessment and business planning, marketing, operations, rate making, and regulatory policy he has helped numerous public and private sector clients evaluate and implement energy efficiency programs.

PROJECT EXPERIENCE

Energy Efficiency Programs and Policy

For the Maryland Energy Administration, provided an analysis of DSM program cost recovery and rate making practices, including assessment of potential models and utility oversight practices.

For a confidential Southwestern electric utility, provided a detailed assessment of DSM cost recovery mechanisms including financial modeling of alternative DSM cost recovery, lost margin, and shareholder incentive mechanisms.

For Entergy Louisiana, LLC, developed an assessment of the potential for DSM to eliminate or defer the need for a 600 MW coal plant, including expert witness testimony, depositions, and participation in Commission proceedings and cross-examination.

For Dominion Virginia Power, estimated achievable DSM savings potential and the ability of DSM to defer the need for a new transmission line. Also prepared expert witness testimony in support of the findings.

For Delmarva Power and Light, estimated achievable DSM savings potential over a 25 year planning horizon and prepared the Integrated Resource Planning (IRP) filing, answered data requests, and participated in regulatory proceedings.

For Potomac Energy Power Company, developed three-year DSM implementation plans for service territories in Maryland and the District of Columbia. Assistance included evaluating programs for cost effectiveness by accounting for customer counts, demographics, and avoided costs unique to each territory and assisting in the preparation of budget estimates and forecasting of participation and load impacts. Prepared regulatory filing documents and participated in hearings before the Maryland Public Service Commission.

For Entergy Corporation, estimated achievable DSM savings potential over a ten year planning horizon for six different Entergy Utilities in Texas, Louisiana, Arkansas, and Mississippi. Oversaw development of DOE-2 and other engineering simulation models to predict energy savings based on local weather and construction characteristics, and forecasted the impacts of a broad range of programs including traditional DSM technologies, solar, PV, time-differentiated pricing, demand response, combined heat and power, and other programs. Program adoption, incentive strategies, and implementation costs were estimated and cost-effectiveness evaluated.

For, Hawaii Electric Light Company, provided screening of potential DSM programs and rate designs, detailed cost-effectiveness analysis, program design and implementation guidelines, review of cost recovery and incentive mechanisms, and preparation of regulatory filing documents.

For, Nova Scotia Power, provided DSM regulatory filing assistance. Mr. Pickles' responsibilities included a detailed assessment of DSM cost recovery and shareholder incentive mechanisms, energy efficiency legislation, minimum appliance standards, energy efficient mortgages, and home energy rating systems.

For Exelon, Mr. Pickles provided detailed energy efficiency program design guidelines and implementation plans for a commercial lighting rebate program and a residential air conditioning tune-up program, with combined expenditures at over $7 million/year.

For Maui Electric, Mr. Pickles provided DSM program screening, cost effectiveness evaluation, and program design and implementation guidelines.

For Centerior DSM Collaborative Mr. Pickles provided a review and analysis of the structure and procedures of a diverse collaborative, developing recommendations for process improvements.

For Iowa-Illinois Gas & Electric, reviewed all DSM implementation activities. Mr. Pickles analyzed Iowa-Illinois' implementation activities for consistency with administrative rules and regulatory expectations.

For Peoples Natural Gas, developed an energy efficient customer financing program. Provided program design and analysis for a customer financing program in multiple states, including program design, solicitation of banks and other financial institutions, contract negotiation, and implementation procedures.

For a consortium of utilities, including: Consolidated Edison, Southern Indiana Gas and Electric, Tucson Electric, and Hawaiian Electric, reviewed energy efficiency financing programs. Included an analysis of the structure and risk profiles of potential financing techniques, a best practices review of the financing programs of other utilities and other industries, market research including conjoint analysis, and development of program design recommendations.

Assessed energy efficiency new business opportunities, including financing and leasing. Assisted in the market research (focus groups, conjoint survey) and managed a project to determine competitive activities in financing, new business planning methodologies, and forecasted profitability for new business ventures.

For Florida Power Corp, developed a DSM financing program including financial structure and process flows.

For Carolina Power and Light, surveyed energy efficiency financing programs. Provided a survey and best practices review of utility financing programs.

For a confidential Midwestern utility, assessed the potential for customer financing programs to provide customer acceptance consistent with that of simple subsidies and rebates. This project included an analysis of the DSM and marketing goals of the utility, an analysis of the change in economic benefit under financing, a review of acceptance experienced by other utilities, and recommendations for program design.

For Entergy Corporation, developed external financing sources for a heat pump marketing program (at approximately $15 million per year), the sale of the existing portfolio of loans (at approximately $60 million), and the outsourcing of all loan origination and servicing activities. This project involved the development of formal bank RFP's, economic analysis of bids, and negotiation with selected institutions.

For multiple clients, prepared an analysis of innovative DSM in a competitive environment. Mr. Pickles provided a summary and analysis of innovative approaches to allocating and collecting the economic costs of DSM programs from program participants and non-

participants. This project includes a survey of all state regulatory commissions and selected utilities, and a comparative analysis of rate impacts, effectiveness and equity.

For Wisconsin Public Service, Mr. Pickles provided a comparative analysis of DSM rebate and DSM loan programs to assess the ability of each to address regulatory goals and to identify the optimal design elements of DSM financing programs.

For Indiana Municipal Power Agency, assessed the rate and revenue impacts of DSM programs. Mr. Pickles provided revisions to IMPA's DSM programs, and provided detailed analysis of the timing and level of rate impacts and revenue fluctuations.

For Hawaii Electric Company, provided a screening of various potential energy efficiency rate designs (including time-of-use rates, interruptible rates, and stand-by generation rates.) Based on the results, Mr. Pickles developed detailed rate designs and implementation plans for the selected rates, and prepared regulatory filings.

For Guam Power Authority, provided an analysis and design of avoided cost based time-of-use and interruptible rates. Mr. Pickles designed and evaluated TOU rates for all customer classes and large customer interruptible rates based on application of avoided costs.

New Business and Product Planning

In more than 10 assignments for energy and utility companies, Mr. Pickles performed new product ideation, characterization, screening, business model creation, market assessment, business plan creation, and provided varying levels of support in obtaining funding, negotiating joint ventures, creating operating plans, identifying acquisition targets, and related start-up activities.

For, Electric Power Research Institute (EPRI) provided an analysis of potential new revenue opportunities for electric utilities. Principal author of the EPRI report *New Service Opportunities for Electric Utilities.*

For a large utility holding company, helped redefine the product development and funding process, developing new standards and procedures for business model assessment and new enterprise management.

For Commonwealth Edison, Mr. Pickles provided an analysis and market potential screening for a wide range revenue and load growth technologies and programs.

For a confidential client, Mr. Pickles developed an assessment of new business opportunities. Performed market research (focus groups, conjoint survey) and managed a project to

determine competitive activities in non-traditional service, to assess new business planning methodologies, and forecast profitability for new business ventures.

For a large municipal energy organization, provided an overview of the market potential and business requirements for a wide range of new products and services. Created an operating framework for the selected new venture and helped identify and negotiate with a joint venture partner.

For Ameren, Mr. Pickles provided a redesign of their new business development process and investment decision making process. He established decision criteria, stage gates, hurdle rates and standards for investment. He also institutionalized this process by assessing two potential new products, performed due diligence and participated in senior management evaluation process of acquisitions.

For a private equity fund, provided an assessment of their investment in an energy management outsourcing company and recommended a revised business model and infrastructure.

For a large real estate investment trust, Mr. Pickles represented senior management in negotiations with a utility to form a joint venture to provide facilities management outsourcing. He assessed core capabilities, contract structure, allocations of risk, control, dissolution, and related issues.

For a confidential utility, conceived and introduced a new product offering involving energy equipment ownership, maintenance, and energy supply. Developed an innovative program wherein price is indexed to measures of customer profitability. Established procedures for managing risk and for sharing benefits of retail access with customers while retaining rights to commodity supply.

For a utility affiliate, developed and introduced end-use pricing (chauffage) program. Obtained $50 million equity commitment from holding company for customer premise equipment and negotiated two such contracts. Integrated energy rights marketing into such contracts providing for agency rights over energy supply.

For a confidential real-estate holding company, established strategy for entering energy services business and performed target identification and acquisition analysis of energy service and energy information companies. Also determined bid price(s) and negotiation strategy.

For a consortium of utilities, managed a multiclient study of customer financing programs, including an analysis of the structure and risk profiles of potential financing techniques, a best

practices review of the financing programs of other utilities and other industries, market research including conjoint analysis, and development of program design recommendations.

For a confidential utility client, developed a business plan for two-way customer communications, CATV, telephony, and other information services in conjunction with utility service. This project included an analysis of the costs and operational savings of potential system configurations, customer acceptance, and related items.

For a confidential client, participated in the valuation and development of a revised business model and growth plan for an energy service subsidiary. Assessed strategic issues (such as product line, sectors, etc.) and tactical issues (e.g., cash management, pricing, etc.) Provided assessment of energy information and automation markets, distributed generation, and related products. Developed new management and staffing structure.

For a water heater manufacturer, developed a business plan for a turn-key financing program. Developed a water heater financing/leasing program to be offered nationally in conjunction with participating utilities. This project included program design, role of financial institutions, marketing approach, and related tasks.

For a utility affiliate, developed integration and bidding strategy for combining commodity supply (in deregulated markets), performance contracting, financing, consolidated billing, and energy information services. Managed the development of joint bids with power marketing subsidiary and secured contracts.

Deal Flow & Due Diligence

For a private equity fund, provided an investigation of potential investments in energy sector technology and outsourcing ventures. Provided business assessment and development, market research, deal structuring, and start-up services.

For a large holding company, prepared for entry into the electrical contracting business. Developed business model, identified acquisition targets, performed valuation and due diligence, participated in negotiations, and developed integration and operations procedures.

For a $600 million venture capital investment fund, provided energy sector investment advice and deal-flow. Provided analyses of energy markets and business plans. Developed investment processes, provided analysis of management teams, and supported due-diligence and deal structuring. Assisting portfolio companies with start-up issues and keiretsu relationships.

For an investment bank, obtained additional investors for spin-out of an energy and home automation subsidiary. Reviewed Offering Memorandum, solicited investors in the U.S. and

Europe, and helped structure the deal.

For a confidential client, provided identification of potential acquisition targets, profiling, analysis of potential synergies, assessment of integration issues, recommended deal terms.

For a utility, defined the approach and led a client team in an assessment of a potential acquisition. Activities included analysis of management team, process mapping, competitive analysis, development of comparables and deal structure, strategic review, due diligence (legal, HR, IT), customer interviews, and related activities.

For a large energy sector investment advisor, assisted in the establishment of a new fund to acquire distressed energy sector assets. Assessed potential strategic partners, market potential, fund structures, and acquisition targets.

Business Unit Executive Management

Led turn around team for a $100M/year struggling energy services business. Performed valuation, management assessment, developed new strategic plan, assessed business processes and funds management. Developed new processes for guarantee management and bonding and assessed growth path and ability to make and integrate acquisitions.

Led turn around team for a $30M/year energy services businesses. Developed new value propositions, marketing plan, sales processes, and contracting procedures. Prepared business plan and developed partners and equity sources for an MBO.

For a confidential utility client, conceived and led a 16-member team in the development of a business plan, securing of funding, development, and introduction of an advanced energy information system. Negotiated profit sharing venture with leading information technology provider and brought product from concept to commercial availability in 11 months.

For a private Internet company, determined all aspects of an aggregation and building portal designed to create purchasing communities for the occupants of large office and multi-family buildings. Raised funding, negotiated venture capital agreements, set requirements, oversaw development, and supervised sales.

Operations

For a confidential energy client, determined market channel strategy and negotiated sales alliances and distributorships with several companies, including power marketers, one of the nation's largest property management companies, a telecommunications company specializing in the office building market, and an electrical contractor. Established wholesale and shared margin relationships.

For a confidential energy client, developed all aspects of corporate marketing strategy including print, television and radio. Introduced disciplined market research into business planning and operations process. Pioneered use of conjoint studies and competitive intelligence in establishing pricing. Introduced observational market research for purposes of identifying new product opportunities.

Determined wholesale marketing strategy and identified competitive targets for the economic development and wholesale marketing rates of a confidential client. This project included a high level analysis of approximately 400 potential targets based upon prices currently paid, the cost structure of their current supplier, potential receptiveness to energy services, and other criteria.

For a utility affiliate, established channel strategy and led negotiations with the world's largest manufacturer of HVAC equipment to co-market energy information systems both domestically and abroad. Relationship includes integration of complementary information systems and co-branding.

For a confidential client, established branding strategy and led negotiations with the world's largest manufacturer of building controls to private label energy systems in certain market segments. Relationship provides for extensive support services (implementation, training, and operations), profit sharing, market exclusivity, and product co-development.

For a utility affiliate, oversaw transition of previously regulated National Account Managers to unregulated business. Developed training program and established code of conduct. Developed market based compensation structures.

For a utility affiliate, developed, in conjunction with an investment bank, bidding strategy and acquisition analysis of large independent energy service company. Extended framework to perform ongoing shareholder value analysis of the acquirer and used this model to establish business planning guidelines.

For a utility affiliate, recruited and trained sales staff from outside the utility industry, set and administered sales goals and methods. Oversaw the development of a lead identification, sales tracking, and contact management system.

For a utility affiliate, led team of business analysts and attorneys in development of contracts for performance contracting, energy information services, chauffage, distributorships, joint ventures, and other business structures. Successfully able to introduce new contracts and risk profiles into utility holding company environment.

EMPLOYMENT HISTORY

ICF Consulting	Vice President	2004-Present
Navigant Consulting	Director, Market Strategy	2000-2003
PHI Management Consultants/Honeywell	Principal, Chief Technology Officer	1999–2000
EnerShop, Subsidiary of Central & South West Services	Vice President Marketing, Development, and Operations (Officer)	1996–1999
Synergic Resources Corporation	Director, Pricing & Product Development	1992 - 1995
Iowa Office of Consumer Advocate/Iowa Utilities Board	Utility Specialist/Senior Analyst	1988-1992

Gregory A. Delizio

DIRECT TESTIMONY OF GREGORY A. DeLIZIO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

Table of Contents

I. INTRODUCTION 1

II. SUMMARY OF TESTIMONY 2

III. GENERAL RATE ADJUSTORS 4

A. Environmental Improvement Surcharge 4

B. Demand-Side Management Cost Recovery Mechanism Proposal 10

IV. RATE DESIGN 15

V. EXISTING RATE SCHEDULES 23

A. Residential Rate Schedules 23

B. Residential Time Of Use Rate Schedules 25

C. General Service Rate Schedules 27

D. General Service Time Of Use Rate Schedules 30

E. Schedules E-34 and E-35 32

F. Irrigation and Water Pumping 33

G. Street Lighting and Dusk to Dawn 34

H. Solar and Green Power Service Schedules 34

I. Critical Peak Pricing 35

J. Other Miscellaneous Rate Modifications 36

VI. PARTIAL REQUIREMENTS SERVICE 36

A. Schedule EPR-5 Partial Requirements Service (Net Metering) 36

B. Schedule EPR-2 Partial Requirements Service (Net Billing) 37

VII. SERVICE SCHEDULES 37

A. Schedule 1 - General Terms And Conditions 37

B. Schedule 4 – Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service 40
C. Schedule 5 – Guidelines for Electric Curtailment 40
D. Schedule 8 – Bill Estimation 41
E. Schedule 10 – Terms and Conditions for Direct Access 42
F. Schedule 15 – Conditions for Governing the Provision of Specialized Metering 43
VIII. CONCLUSION 45
Statement of Qualifications ..... Appendix A
Proposed Redlined EIS Adjustment Schedule ..... Attachment GAD-1
Proposed EIS Plan of Administration ..... Attachment GAD-2
Proposed Redlined DSMAC Adjustment Schedule ..... Attachment GAD-3
Proposed DSMAC Plan of Administration ..... Attachment GAD-4
Proposed Disaggregated Schedule E-32 ..... Attachment GAD-5
Proposed Disaggregated Schedule E-32TOU ..... Attachment GAD-6
Proposed Redlined Schedule Solar-3 ..... Attachment GAD-7
Proposed Redlined Schedule 1 ..... Attachment GAD-8
Proposed Redlined Schedule 4 ..... Attachment GAD-9
Proposed Redlined Schedule 5 ..... Attachment GAD-10
Proposed Redlined Schedule 8 ..... Attachment GAD-11
Proposed Redlined Schedule 10 ..... Attachment GAD-12
Proposed Redlined Schedule 15 ..... Attachment GAD-13

DIRECT TESTIMONY OF GREGORY DeLIZIO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Gregory A. DeLizio, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Manager of Pricing for Arizona Public Service Company ("APS" or the "Company").

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. My qualifications are set forth in Appendix A to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's proposed changes to its current service and rate schedules. In addition, my testimony will propose modifying the Company's Environmental Improvement Surcharge ("EIS") into a mechanism that would provide for more timely recovery of the actual expenses (both capital and operating) associated with environmental improvements. My testimony will also address APS's request for improved demand-side management cost recovery mechanisms to encourage the development of Demand Side Management ("DSM"); specifically, to (1) recover uncollected fixed costs (lost margins) associated with DSM, (2) enhance the Company's performance incentive, and (3) allow for the recovery of program costs in the same year that they are spent through the Demand-Side Management Adjustment Charge ("DSMAC").

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I describe and sponsor the H Schedules of the Company's Standard Filing Requirements ("SFR"). These Schedules reflect an analysis of the impacts of the proposed rate schedules under the Company's requested increase in base rates as shown on SFR Schedule A-1, sponsored by APS Witness David Rumolo. I also support the pro forma on SFR Schedule C-2 (page 11, column 33) to annualize the revenue APS receives from retail customers to reflect the change in retail base rates that became effective July 1, 2007.

I discuss the proposed modification to the EIS and how it should be redesigned to reduce regulatory lag. The modified EIS will allow the Company to recover the additional costs of environmental improvement projects. Such projects have required substantial capital investment to date, and that investment will continue to be required on an annual basis. By converting a fixed EIS to an adjustor mechanism, the Company would be able to modify the EIS charge on an annual basis based on the actual costs of such projects as was recommended by the Administrative Law Judge ("ALJ") in the last APS rate proceeding.

The Company is also requesting to modify the DSMAC to encourage the development of efficient DSM programs by aligning utility incentives with the delivery of such programs. As set forth in the testimony of APS Witness David K. Pickles, improved DSM mechanisms are critical if additional and more efficient programs are to be implemented. In response, the Company is proposing to enhance its current mechanisms to encourage additional DSM spending by implementing additional incentives including: the collection of otherwise uncollected fixed costs resulting from implemented DSM programs;

the earning of an increased performance incentive by removing the existing cap on APS's incentives (currently set at 10% of program expenditures); and the recovery of program costs in the same year that they are spent through the DSMAC.

For residential customers, I discuss the Company's request to freeze the "Series 1" Time-Of-Use ("TOU") rates, *i.e.*, Schedules ET-1 and ECT-1R. This will encourage APS customers to choose either the Company's current "Series 2" TOU rates (ET-2 and ECT-2) or the Company's new proposed ET-SP rate. APS is also proposing to modify E-12 to include the addition of a fourth and higher priced block rate for customer consumption greater than 3,000 kWh monthly. The intent is to encourage both energy conservation and the switching to TOU by large E-12 customers. The Company also proposes to freeze rate Schedule Solar-2. Finally, APS is requesting to increase all residential basic service charges in order to more appropriately collect a larger portion of fixed costs from its customers through non-energy rates.

On the non-residential side, I discuss the Company's proposal to disaggregate Schedule E-32 and E-32TOU into four new rate schedules and cancel partial requirement rate schedules E-32R, E-51 and E-55. Both of these steps are consistent with Decision No. 69663 (June 28, 2007). I also address less significant changes to other general service rate schedules. As with residential rates, and for the same reason, APS is asking to increase the basic service charge for general service customers.

In an effort to encourage greater customer participation of solar power, the Company proposes to offer customers two new subscription options of 10% and 35% to supplement the current options on Schedule Solar-3 of 100% and 50%.

Also, the Company proposes to provide customers with increased flexibility in expressing support for renewable energy by permitting the combination of subscriptions of power under Schedule Solar-3 with Green Power Block ("GPS-1") and Green Power Percentage ("GPS-2"). Although APS has proposed these changes as part of this rate filing to insure that there is a vehicle for their consideration, the Company may also seek similar modifications to its Green Power Service Schedules 1 and 2 in a separate proceeding later this year.

The Company seeks to modify Service Schedules 1, 4, 5, 8, 10 and 15 in a number of mostly minor respects. These changes will either clarify provisions of the Schedules and/or conform them to sound business practices under current circumstances.

Finally, APS requests that the Commission authorize APS to continue deferring uncollected fixed costs for its net metering program under Schedule EPR-5, as authorized under Decision No. 69663, and to seek their recovery in a subsequent rate proceeding. Although at present such costs are small, they may eventually be quite significant; especially when the Commission's proposed net metering rules are implemented.

III. GENERAL RATE ADJUSTORS

Q. IS APS PROPOSING ANY MODIFICATIONS TO ITS ADJUSTMENT SCHEDULES?

A. Yes. My testimony will propose modifications to the EIS and DSMAC. Modifications to the Transmission Cost Adjustment ("TCA") are discussed by Mr. Rumolo.

A. Environmental Improvement Surcharge

Q. IN THE LAST RATE CASE, THE COMMISSION APPROVED THE ESTABLISHMENT OF AN ENVIRONMENTAL IMPROVEMENT SURCHARGE TO HELP FUND NECESSARY ENVIRONMENTAL PROJECTS. IS THE CURRENT ENVIRONMENTAL IMPROVEMENT SURCHARGE SUFFICIENT TO ALLOW THE COMPANY TO ADDRESS ENVIRONMENTAL CONCERNS?

A. No. It is evident that the Commission has a real commitment to protecting Arizona's environment, and through its past decisions, the Commission has demonstrated that environmental protection is a compelling public interest and that the use of surcharges is an appropriate mechanism to establish programs that support environmental protection. In Decision No. 69663, the Commission recognized the benefit of continuing its longstanding commitment to protect the environment by allowing APS to implement the EIS. However, the EIS currently collects only $4.3 million per year (roughly $2.6 million after tax), and the funds are accounted for as contribution in aid of construction ("CIAC"). APS's projected capital environmental improvement costs for the Cholla Generating Station alone are more than $332 million through 2012. Thus, the surcharge does not recover any significant portion of these costs. APS is proposing a modification to the surcharge mechanism that will allow the Company to proactively confront environmental concerns and support the infrastructure to do so.

Q. WHY IS A MODIFICATION TO THE EIS NECESSARY AT THIS TIME?

A. APS is committed to securing our existing fleet of fossil fuel units for the long-term benefit of our customers and to ensuring these units comply with all environmental requirements. Currently, the EIS recovers a small portion of the capital expenditures associated with environmental improvements. APS believes it is appropriate to expand and expedite the recovery of the costs

necessary for complying with existing laws and anticipated future requirements, which is in the best interests of APS customers and the state of Arizona.

Q. PLEASE PROVIDE AN OVERVIEW OF THE MODIFICATIONS SOUGHT TO THE ENVIRONMENTAL IMPROVEMENT SURCHARGE.

A. APS is recommending that the Commission modify the EIS by allowing for a return on investment and a recovery of expenses rather than treating the investment as CIAC. This modification will reduce the up-front dollar rate impact on customers of such environmental improvements. In addition, the Company proposes to implement an adjustor mechanism that will allow the Company to modify the EIS charge on an annual basis as needed to recover actual costs of environmental improvement projects. These changes are consistent with the ALJ's Recommended Order in Decision No. 69663 with regard to what was then called the "environmental improvement charge" or "EIC." The proposed modification to the EIS would continue to yield an energy-based $/kWh charge that would be assessed to all retail kWh sold by APS, with certain exceptions discussed herein.

Q. WOULD MODIFYING THE EIS REDUCE REGULATORY LAG?

A. Yes. A utility may not be able to collect revenue related to a particular investment until the Commission issues an order within the context of a general rate case. Inevitably, there is a significant delay between the construction expenditures and an issuance of a Commission rate order. That regulatory lag prevents the timely recovery of costs associated with even those investments that are the result of government mandates and which are associated with no new revenues or cost savings. Thus, the goal in designing the original mechanism proposed by APS in the last rate case and in the suggested changes

to the EIS in this case is to reduce this regulatory lag on environmental investments, while maintaining a vehicle for appropriate regulatory oversight of such investments. *See* Schedule EIS (Attachment GAD-1) and the modified EIS Plan of Administration (Attachment GAD-2) which incorporate the proposed changes.

Q. HOW CAN MODIFYING THE EIS MITIGATE THE COST OF ENVIRONMENTAL PROJECTS?

A. The simple rules of supply and demand indicate that waiting until mandated compliance is evident can increase costs as other companies compete for the technology, equipment and labor required for capital improvements. By doing these projects before this increased demand, APS can avoid the higher costs driven by such increased demand.

Q. WHAT KINDS OF COSTS WOULD BE INCLUDED IN THE EIS?

A. APS has incurred environmental improvement expenditures and will continue to incur such costs on an annual basis. Those expenditures include costs associated with the investment necessary for installing and maintaining the environmental upgrades at APS's facilities. These include, but are not limited to, the return on capital, associated income taxes, depreciation, operation and maintenance expenses, and property taxes.

Q. CAN YOU BE MORE SPECIFIC ABOUT THE COSTS TO BE INCLUDED IN THE EIS?

A. Yes. APS placed in service in November 2007 four projects at Cholla Unit 1 that include a baghouse installation, scrubber upgrade, low NOx burners and a stack liner installation. These projects are, of course, included in the Company's proposed rate base and would not be recovered through the EIC. But, in

addition, APS is planning at least sixteen additional environmental projects totaling an estimated $294,000,000 at the Cholla Power Plant through 2012. Additional improvements at the Cholla, Four Corners and Navajo Power Plants may also be necessary and/or desirable in the near future. Although, in some cases, the specific levels of emissions controls or reductions that will be required have not yet been finalized, APS is planning emission control improvement projects based upon anticipated environmental requirements. Typically, these types of projects take several years to complete. APS believes, in some cases, it is appropriate to be in compliance before a mandate is effective rather than wait until the last minute.

Q. SPECIFICALLY, HOW SHOULD THE COMMISSION MODIFY THE EIS?

A. The Company proposes that the EIS work as an adjustor mechanism. The charge will still be calculated based upon historic costs, both capital and operating, associated with the qualifying approved projects. The EIS is calculated based on applicable EIS revenue requirements divided by the forecast estimated retail sales over the 12-month period that the rate will be in effect. The adjustor would allow the Company to recalculate this charge on an annual basis. The Company would file for recovery of such costs with the Commission by February 28 of every year.

Q. WILL THE EIS CONTINUE TO APPLY ONLY TO STANDARD OFFER CUSTOMERS?

A. Yes. The EIS (¢/kWh) would continue to be applied to all kWh used by Standard Offer customers. Customers served under SP-1, Solar-3, GPS-1 and GPS-2 will not be assessed the EIS for green/solar energy subscribed. In addition, customers that subscribe to Schedule Solar-2 will not be paying the

EIS because those customers have a stand-alone solar electric system that is not connected to the Company's distribution system and, thus, do not use APS generation for those kWh.

Q. IS THE COMPANY PROPOSING THAT THE EIS BE SET IN THIS PROCEEDING?

A. The Company has proposed a pro-forma adjustment to the Test Year for the Cholla Generating Station environmental projects scheduled to be installed by May 2008 as described in the testimony of APS Witness Daniel Kearns. If the Commission adopts this adjustment in base rates, the initial EIS would calculate at 0.000179/kWh. Because the calculation of the EIS is only slightly above the current value of $0.00016/kWh, APS would not propose a change to the current EIS and would recover these additional EIS costs in the 2010 EIS filing.

Q. HAVE YOU CALCULATED WHAT THE INITIAL EIS CHARGE WOULD BE IF THE COMMISSION ELECTS NOT TO RATE BASE THOSE CHOLLA COSTS AT THIS TIME?

A. Yes. Absent the approval of the proforma adjustment, the initial Company EIS charge would be $0.000239 kWh and would be effective with customer bills rendered after the date of a decision in this docket.

Q. WHAT FACTORS DID THE COMPANY USE TO CALCULATE THE MODIFIED EIS ADJUSTMENT?

A. To compute the EIS requested in this filing, APS used cost components that are consistent with the cost-of-capital, depreciation, property tax and income tax assumptions used in this general rate case fling. Therefore, the debt component of 46%, the equity component of 54% and the Company's proposed equity cost of 11.5% were used in calculating the requested EIS. Property tax rates specific to the Cholla Power Plant are included, and the environmental assets are

depreciated over 40 years. For income tax purposes, the environmental assets are depreciated over 20 years. However, should a project qualify as a Certified Pollution Control Facility as provided for under the Federal Energy Act of 2005, tax recovery may be based on a lesser period.

Q. GIVEN THE FACT THAT APS RECORDS ACCUMULATED FUNDS USED DURING CONSTRUCTION ("AFUDC") FOR ITS CONSTRUCTION PROJECTS, HOW CAN THE COMMISSION BE SURE THAT THE COMPANY IS NOT RECOVERING TWICE IF THE COMMISSION ALLOWS RECOVERY OF CONSTRUCTION WORK IN PROGRESS ("CWIP") COSTS OF ENVIRONMENTAL PROJECTS SEPARATELY THROUGH THE EIS?

A. APS will establish internal accounting procedures to ensure that such a situation will not occur. Specifically, the Company will put in place accounting procedures to discontinue collecting AFUDC on projects when that same investment is collected through the EIS or when that investment is put in rate base. In this way, the Commission can be assured that the Company will not recover environmental costs twice.

B. Demand-Side Management Cost Recovery Mechanism Proposal

Q. IS APS RECOMMENDING ENHANCEMENTS TO THE CURRENT DSM COST RECOVERY MECHANISM?

A. Yes. As Mr. Pickles discusses in his testimony, the currently-approved DSM mechanism is not on par with the ratemaking mechanisms approved by leading states in the area of DSM, thereby effectively limiting further investment by APS in additional cost-effective DSM programs.

Q. PLEASE DESCRIBE HOW APS RECOVERS DSM PROGRAM COST TODAY.

A. Decision No. 67744 (April 7, 2005) addressed the recovery of DSM program costs from two sources. Base retail rates generate $10 million per year and spending over the base retail rate level is collected through the DSMAC. During the Test Year, the DSMAC was zero. By the end of 2007, approved program spending exceeded the base level by approximately $3 million. However, because this amount would result in a very small DSMAC, the Company proposed in its February 15, 2008 filing that the balance of approximately $3 million should be retained in the DSMAC balancing account for later recovery. Decision No. 69663 modified the DSMAC to allow interest to accrue on un-recovered DSMAC balances. The interest rate was established at the Federal Reserve Statistical Release Nominal Treasury Constant Maturities rate. Currently, the Company has an application before the Commission seeking approval of expenditures for 2008-2010.

Q. DOES THIS APPLICATION PROPOSE CHANGES TO THE RECOVERY OF COSTS ASSOCIATED WITH DSM PROGRAMS?

A. Yes. Mr. Pickles discusses why the Company's proposal for modifying the current DSM mechanism is necessary to promote and expand APS energy efficiency programs. In that light, the Company is proposing the following:

a. APS would collect otherwise uncollected fixed costs due to implemented DSM programs based on MWh program impacts in the prior year priced at the average retail rate less average variable costs for fuel and purchased power. These lost fixed cost contributions should be recovered through the DSMAC each year based on actual additional reductions in sales due to DSM implemented in the prior year plus reductions in such year from DSM implemented in previous years since

the last rate case but still within the life of the DSM measures implemented.

b. APS should have an opportunity to earn an increased performance incentive by removing the existing cap on APS's incentives (currently set at 10% of program expenditures). APS proposes to retain the current sharing relationship between ratepayers (who receive 90% of the net benefits of the programs) and shareholders (who receive 10%).

c. APS would recover program costs in the same year that they are spent. This amount should be based on projected DSM spending for both approved and pending programs, with a true-up to actual spending and recoveries in the following year.

Q. WOULD YOU PLEASE DESCRIBE WHAT YOU MEAN BY UNRECOVERED FIXED COSTS?

A. Yes. A significant portion of the Company's revenue requirement is made up of fixed costs, such as depreciation, taxes, plant-related O&M expenses, debt service and return to shareholders. I refer to these components as "fixed" in that the Company must incur them irrespective of the amount of energy delivered to customers. These costs are comparable to the monthly or other fixed payments a consumer must make in order to have a car. The leasing or finance company, the insurance company, and the state all expect to be paid whether the car is parked in the garage or driven daily.

Unlike the entities in my car example, which directly bill the car owner for these fixed amounts, APS rates are designed to recover in each kilowatt hour sold a portion of fixed costs incurred to serve customers. By their nature, successful energy efficiency DSM programs reduce the amount of energy sales made to

customers. Because the Company's rates are volumetric based, *i.e.*, based on the amount of energy customers consume, programs that reduce that volume naturally reduce the amount of net revenue received to pay for fixed costs. Although DSM programs allow the Company to save variable costs associated with energy delivery (namely, fuel and purchased power), which savings are in very large part passed on automatically to APS customers through the PSA, the Company cannot save on its fixed costs in the short to intermediate term. DSM programming thus results in a margin of lost revenue to the Company. Two consequences result. First, between rate cases, the inability to recover these costs exacerbates earnings attrition and, thus, creates a disincentive to companies to pursue effective DSM programs. Second, when rates are reset, those rates will be at only marginally higher levels. This effect is not uncommon since it can also occur under the Renewable Energy Standard Tariff ("REST"). In the long run, comprehensive and successful DSM programs may reduce fixed costs, which will mitigate the second issue, but it will not reduce the earnings attrition that will occur between rate cases.

Q. HOW COULD THE UNCOLLECTED FIXED COSTS BE RECOVERED?

A. There are several methods to address uncollected fixed costs. One approach that is gaining acceptance (particularly in the gas utility industry) is rate decoupling. Under decoupling, a utility's revenues are either established on a per customer basis or stated as a specific revenue level in the context of a rate case. In either case, annual adjusters are used to ensure that revenue levels are met regardless of sales volume changes. Another approach is to recognize the uncollected fixed costs as program implementation costs and allow the Company to recover those

costs through an adjustor such as the DSMAC. APS has proposed the latter approach as less complicated and more directly addressing the specific problem.

Q. WHAT IS THE COMPANY'S PROPOSAL PERTAINING TO THE PERFORMANCE INCENTIVE CAP?

A. As supported by Mr. Pickles, the Company is proposing a DSMAC that eliminates the performance incentive cap which is currently based on 10% program spending.

Q. WHY IS THE COMPANY PROPOSING TO CHANGE FROM A HISTORICAL TO A PROSPECTIVE COLLECTION OF PROGRAM COSTS?

A. The current DSMAC is a retrospective one in that cost recovery occurs in the year *after* the Company incurs its DSM-related expenses. Although APS invests its capital dollars in those programs, it is not permitted to earn any return or interest on that investment during the lag time between its payment of those costs and recovery. In order to relieve the lost earnings due to DSM during that lag time, the Company requests that its DSM cost recovery be based on the Company's expected spending level for pending and approved programs.

Q. IF THE COMMISSION WERE TO DENY THE PROSPECTIVE COLLECTION OF DSM PROGRAM COSTS, DOES THE COMPANY HAVE AN ALTERNATIVE RECOMMENDATION?

A. Yes. If the Commission were to deny the prospective collection of DSM program costs, the Company would propose that costs incurred on a historic basis be adjusted for the time value of money using the Company's weighted average cost of capital.

Q. HOW IS THE COMPANY PROPOSING THE ADJUSTMENT CHARGE RATE BE CALCULATED?

A. The DSMAC rate for a year would be calculated by dividing the DSMAC recoverable costs (current year budget costs for approved programs plus/minus true-up of previous periods over/under collection of DSMAC revenues plus uncollected fixed costs plus incentives) by the kWh (residential and those general service customers whose billing does not include demand charges) or kW (for general service customers whose billing includes demand charges) used by customers in the previous calendar year. *See* Redlined Schedule DSMAC (Attachment GAD-3) and the DSMAC Plan of Administration and Schedules 1-3 (Attachment GAD-4).

Q. WILL THE CHARGE APPLY TO ALL CUSTOMERS AND ON THE SAME BASIS?

A. Yes. The charge will apply to both Standard Offer and Direct Access customers. Consistent with the current provisions, General Service customers that are billed for demand will pay a per kW charge and non-demand billed General Service customers will pay a per kWh charge. All residential customers will pay a per kWh charge.

IV. RATE DESIGN

Q. WOULD YOU DESCRIBE THE PROCESS USED TO DEVELOP THE PROPOSED RATES?

A. Yes. The starting point in the rate design process is the cost of service study discussed in Mr. Rumolo's testimony. The cost of service study allocates the costs of providing service to each of the major classes of customers, as well as various sub-classes and rate schedules. If the cost of service study were the only determinant for setting rates, each rate classification would recover APS's proposed rate of return, and all rate schedule prices would reflect unit costs, expressed as Demand Charges, Energy Charges, and Customer Charges.

However, many other considerations were taken into account in designing the proposed rates, which resulted in individual rate schedules that differ in appearance and application from the overall proposed rate of return and rate design pricing elements.

Q. OTHER THAN THE COST OF SERVICE STUDY, WHAT OTHER FACTORS WERE CONSIDERED WHEN DESIGNING THE PROPOSED RATES?

A. The Company considered several other factors. Among the most important were rate and revenue stability and continuity. For this reason, the major classes of customers, including Residential, Street Lighting and Dusk to Dawn, have each been given a percentage increase to make the classes more in line with its cost of service even though strict adherence to the results of the cost of service study would indicate higher increases are supportable. General Service and Irrigation have each been given a lower increase to make the class more in line with its cost of service. APS has also taken steps to disaggregate its E-32 rate as required by Decision No. 69663 to make the rate more in line with its cost of service. That being said, the individual rate schedules have been designed to depart from strict cost of service adherence as necessary, so that differences in the increases that individual customers will experience will be moderated to the extent reasonable. Additional considerations in developing the proposed rate schedules were customer understandability, acceptance and ease of administration. In other words, APS attempted to simplify the specific rate schedules and the presentation of the Company's tariff in general. Consideration of these factors is in conformance with the traditional aspects of rate design. The proposed increases by rate schedule are shown in SFR Schedules H-2 and H-3.

Q. WOULD YOU PLEASE DESCRIBE THE "H" SCHEDULES YOU ARE SPONSORING?

A. Yes. The "H" Schedules are a series of summaries that present an analysis of the impacts of the proposed rate schedules under the Company's requested increase in base rates as shown on Schedule A-1.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-1?

A. Yes. SFR Schedule H-1 provides a summary of the revenue impact on each major customer classification, *e.g.*, Residential, General Service, Irrigation, etc. This schedule compares the revenue generated under the proposed rate schedules with the revenue generated under present rate schedules. Due to the Company's request for a new base fuel rate, an additional column was added to show the net impact of the Company's request.

To develop the data found in the column entitled "Present Rate Schedules," APS started with actual revenue from the Test Year, and then made a series of annualizations and normalization adjustments to that data. One adjustment as shown on SFR Schedule C-2 (page 11, column 33) was made to annualize the rate increases that became effective in July 2007 pursuant to Decision No. 69663. The purpose of these adjustments was to enable APS to compare existing and proposed rate schedules on an "apples-to-apples" basis. A detailed explanation of the development of billing determinants and the proof of revenues for present and proposed rates is provided later in my testimony.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-2?

A. Yes. SFR Schedule H-2 presents the information found in SFR Schedule H-1 in a more detailed format. The comparisons of current and proposed revenue are shown by rate schedule, whereas H-1 data is presented on a class basis. SFR

Schedule H-1 is actually a summary of the data found in H-2. A column has been added under proposed rates to separately identify revenues collected through the proposed TCA mechanism and in order to identify the net impact of the proposed increase on customers.

Q. HAVE YOU SUMMARIZED THE EFFECTIVE BILL CHANGES CUSTOMERS WILL EXPERIENCE?

A. Yes. SFR H-1 and H-2 demonstrate the impact of changes in base rates. As discussed by APS Witness Rumolo, the actual bill changes customer classes will experience, as shown on H-1 and H-2, are lower than the total base rate increase because a portion of the increase related to fuel would have flowed through the PSA had the higher fuel costs not been included in base rates. *See* Attachment DJR-6 to APS Witness Rumolo's Direct Testimony for the average impact on customers' monthly bills.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-3?

A. Yes. SFR Schedule H-3 presents comparisons of the specifics of each rate schedule. These specifics include details such as the basic service charge, billing blocks, energy charges, and demand charges. Although the Company's proposed rate schedules have been functionally unbundled, the information shown on H-3 is presented on a bundled basis to allow for easier comparisons, and because all APS customers currently purchase a bundled product. Rate schedules that were cancelled in the last rate case in Decision No. 69663 are so noted on H-3. Adjustor rate schedules DSMAC, REST, CRCC, PSA, EIS, TCA, GPS-1 and GPS-2 are shown at the end of Schedule H-3, and it is noted that their charges can be modified between rate cases with Commission approval. No changes in the rates for these adjustors are being proposed in this case.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-4?

A. Yes. SFR Schedule H-4 presents typical base rate bill comparisons for APS's major rate schedules under existing and proposed rates. Bill comparisons are presented for varying levels of consumption and for seasons, when applicable. The "add-ons" of RES, EIS, PSA, CRCC, sales tax, franchise fees, and Regulatory Assessment have not been included in the bill comparisons, and their impact will vary slightly from community to community. SFR Schedule H-4 does not, however, reflect the reclassification of PSA revenues into base rates. Neither does it reflect any potential offset for the Company's proposed Impact Fee.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-5?

A. Yes. SFR Schedule H-5 presents a series of bill frequency analyses for all schedules. This information includes the number of bills and energy consumed based on specified blocks of consumption. This schedule also includes demand stratification for those applicable rate schedules. Workpaper GAD_WP9 shows the reconciliation between the adjusted billing kWh determinants used for the H-2 and H-3 Schedules with the unadjusted billing determinants shown in Schedule H-5.

Q. PLEASE PROVIDE A HIGH LEVEL DESCRIPTION OF THE PROOF OF REVENUE PROCESS FOR RATE DESIGN AND HOW BILLING DETERMINANTS ARE DEVELOPED AND THEN USED IN SCHEDULE H-2.

A. In order to begin the development of each individual rate schedule, it is necessary to determine the total number of kWh and kW the Company's customers used during the test year by extracting that information from the Company's billing system. These billing parameters are differentiated by

season, time-of-use and delivery service voltage as applicable for each rate schedule. The number of customers billed during the test year is also retrieved from the billing system. These quantities are commonly referred to as "billing determinants," and they are used to develop appropriate rate designs which will then, in total, recover the Company's proposed revenue requirement.

As is evident, there are multitudes of billing determinants for the test year. Applying current rate components to these billing determinants, however, will not exactly replicate actual test year revenue. Therefore, these detailed billing determinants must be "calibrated" by calculating the test year revenue using these determinants, then comparing those recalculated revenues to the actual test year revenue for each rate schedule. The same billing determinants are applied to both present and proposed rates to calculate an "apples to apples" revenue for comparison.

Q. WHY IS THE COMPANY UNABLE TO EXACTLY MATCH THE RECORDED LEVEL OF TEST YEAR REVENUE WITH ITS RECALCULATION OF THAT REVENUE USING TEST YEAR BILLING DETERMINANTS?

A. While very accurate, this process can never exactly replicate the recorded test year revenue. This is because the revenue recalculation process cannot precisely replicate every operation in the billing system. For example, new rates were implemented in July 2007 which was during the test year. Customer bills for July were prorated depending on their billing cycle. We would not replicate this proration process because we do not separately recalculate billing for each of our one million customers for that month, but rather we recalculate billing using the summarized billing determinants for APS customers. This factor alone could account for roughly two-thirds of the difference between revenues calculated

from extracted billing determinants and actual test year revenue for residential rates. Other billing factors that may contribute to this difference include calculations of customer contract minimum bills, prior period adjustments made during the test year, and other similar routine billing operations.

Q. HOW IS THIS CALIBRATION PROCESS USED?

A. Although the billing calculation calibration factor varies by rate schedule, the overall difference between the test year's billing recalculation revenue and the actual test year revenue was -0.71%, which means that the total billing recalculation was 0.71% higher than the actual test year revenue. The percentage calibration factor for each rate schedule is applied to present revenues and proposed revenues described above to calibrate the revenue for these various billing operations that are not precisely captured by the billing determinant method of recalculating test year revenue.

Q. HOW DOES THE COMPANY INCORPORATE UNBILLED REVENUES IN THE RATE DESIGN PROCESS?

A. Net unbilled revenues result from monthly accrual adjustments to the billed revenue to account for: (1) kWh that were consumed prior to the test year but billed during the test year (*i.e.*, for certain billing cycles in January of 2007); and (2) kWh consumed during the test year but billed in 2008 (*i.e.*, for certain billing cycles in December 2007). The net unbilled revenues are recalculated using an average cents per kWh for winter rates. Winter rates are used because all the net unbilled kWh occurred in January and December of the calendar test year. The unbilled revenue is included in the adjusted present and proposed revenue shown on Schedules H-1 and H-2, but is shown separately in the detailed workpaper GAD_WP4.

Q. HOW DID THE COMPANY TREAT RATES THAT WERE CANCELLED DURING THE TEST YEAR OR WHICH APS IS PROPOSING TO CANCEL IN THIS PROCEEDING?

A. A number of rate schedules that were cancelled in the Company's prior rate case (Decision No. 69663) allowed customers to be billed on those cancelled rates during the test year, and in some cases, for up to a year due to transitional plans. The Company has also requested that several other rates be cancelled in the instant application. However, because the cancelled rates will not be available when new rates from this application are implemented, both the present revenue and proposed revenue are calculated by billing those customers on their most likely alternative, either because such alternative is the rate that is most similar to the cancelled rate or because the selected alternative is the only rate then applicable to the customer.

For example, residential inclining block rate schedule E-10 was cancelled in Decision No. 69663 in July 2007. A temporary rate, E-10 interim, was made available to customers for a one-year transitional period. Therefore, from January through June 2007, the recalculated test year revenue for the E-10 rate was used, and from July through December 2007, the E-10 interim rate was used. However, the adjusted present revenue and adjusted proposed revenue were both calculated based on rate E-12, which is the most likely alternative inclining block rate E-10 customers will choose after the transition period ends. The revenue treatment for cancelled rates is provided in workpaper GAD_ WP8.

Q. DOES SCHEDULE H-2 INCLUDE PROFORMA ADJUSTMENTS FOR REVENUE AS SHOWN ON SCHEDULE C-2?

A. Yes, proforma adjustments made to the test year kWh to normalize or annualize for weather, customer growth, and DSM program impacts are included. The

relevant billing determinants for the test year are then applied to all the current charges in each rate schedule to develop the unadjusted present revenue.

The present revenue for the proforma kWh adjustments is derived by using an average cents per kWh from the unadjusted present revenue (prior to proforma adjustments) times the proforma kWh adjustment. Adding the unadjusted present revenue to the proforma adjustments results in the adjusted present revenue, which is the "starting place" for developing proposed rates.

Q. WHAT RATE DESIGN ISSUES ARE BEING ADDRESSED BASED ON THE ORDER IN THE COMPANY'S PREVIOUS RATE CASE?

A. The Commission ordered several rate modifications in Decision No. 69663, each of which the Company is addressing in this application. First, the Commission approved the cancellation of partial requirement rate schedules E-32R, E-51 and E-55. Second, the Commission ordered APS to propose one or more demand response programs including a critical peak pricing program. The latter are discussed in detail by APS Witness Charles Miessner. Also within the last rate case, APS agreed with Staff and other parties that the Company would propose a separation of the general service Rate Schedule E-32 into at least three new rate schedules based on customer size.

V. EXISTING RATE SCHEDULES

A. Residential Rate Schedules

Q. WOULD YOU PLEASE GIVE A GENERAL DESCRIPTION OF THE EXISTING RESIDENTIAL RETAIL RATE SCHEDULES?

A. Currently, APS has seven active residential rate schedules – four time-of-use rate schedules (Schedules ET-1, ECT-1R, ET-2, and ECT-2), one inclining block rate schedule (Schedule E-12), and two rate schedules for special assistance.

Schedule E-3 provides discounts for qualifying low-income customers. Schedule E-4 provides a discounted rate to customers who use electricity for medical care equipment. Rate Schedules E-10 and EC-1 were eliminated by the Commission in Decision No. 69663. Customers were given a one-year transition period to select another rate, which will expire on July 1, 2008.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES IN THE EXISTING RESIDENTIAL RATE SCHEDULES?

A. The proposed changes to the existing residential rate schedules are as follows:

- The "Series 1" TOU rates, *i.e.*, Schedules ET-1 and ECT-1R, will be frozen and will not be available to new customers or to existing customers who switch service locations. Schedule ECT-1R will receive an increase that is above the average increase for the residential class and slightly higher than the "Series 2" TOU rates to better reflect cost of service. For Schedule ET-1, the on-peak price will continue to be approximately three times the off-peak price in the summer. However, the difference between winter on-peak and off-peak prices will be reduced to better reflect the lower cost differential in those periods.
- Rate Schedule E-12 will receive an increase slightly lower than the overall Company increase. In addition, E-12 will see the addition of a fourth higher priced block rate for customer consumption greater than 3,000 kWh per month. Prices for the remaining blocks were then adjusted accordingly. The intent of this new block is to encourage energy conservation for the Company's largest residential users. This change will also provide an additional price incentive for such customers to switch to a TOU rate.
- The "Series 2" TOU rate schedules ET-2 and ECT-2 will receive

approximately the same increase as the "Series 1" TOU rates. For Schedule ET-2, the on-peak price will continue to be approximately four times the off-peak price in the summer. Similar to ET-1 and ECT-1, the difference between winter on-peak and off-peak prices will be reduced to better reflect the lower cost differential in those periods.

- The bundled basic service charges for all residential rate schedules were increased between about 2¢ to about 9¢/day to better reflect the fixed costs associated with the customer being connected to APS's system. These costs include metering, meter reading, billing, customer accounting and a small portion of fixed distribution costs.

B. Residential Time Of Use Rate Schedules

Q. WOULD YOU PLEASE GIVE A GENERAL DESCRIPTION OF APS'S CURRENT TIME-OF-USE RATES FOR RESIDENTIAL CUSTOMERS?

A. Yes. Currently APS offers four residential TOU rate schedules. The "Series 1" rates, ET-1 and ECT-1R, have a 12-hour on-peak period from 9 a.m. to 9 p.m. weekdays. ECT-1R has a demand charge that only applies to the on-peak period as well as on- and off-peak energy charges. ET-1 has energy charges only; the summer on-peak energy charge is three times as high as the off-peak charge.

In July 2006, APS introduced the "Series 2" rates, Schedules ET-2 and ECT-2, to encourage customers to shift more load to the off-peak period, especially during the summer months. The "Series 2" rates have a 7-hour on-peak period from noon to 7:00 p.m. weekdays. In addition, the all-energy rate, Schedule ET-2, has a summer on-peak price that is four times as high as the off-peak price.

Q. HOW MANY CUSTOMERS PARTICIPATE IN THE COMPANY'S RESIDENTIAL TIME OF USE PROGRAMS?

A. As of December 2007, nearly 453,000 APS residential customers are participating in a TOU rate (approximately 400,000 on the "Series 1" rates and 53,000 on the "Series 2" rates) which represents 46% of total residential customers and 61% of residential kWh sales. These figures are likely to increase significantly when the transition period for cancelled residential Schedules E-10 and EC-1 expires July 1, 2008. In terms of percentage and total number of residential customers, APS has the most successful residential TOU program in the United States. The Company's TOU program is also one of the longest-standing, having first been approved by the Commission in the early 1980s.

Q. HOW DOES THE COMPANY PROPOSE TO MODIFY ITS RESIDENTIAL TOU PROGRAMS?

A. The Company is proposing several changes to its residential time-of-use rate which include freezing the "Series 1" TOU rates (ET-1 and ECT-1R) and adding a new Rate Schedule ET-SP, which is similar in design to the ET-2 rate schedule but includes a "super peak" period. Mr. Miessner discusses this offering in more detail.

Q. WHY IS THE COMPANY PROPOSING TO FREEZE THE SERIES 1 TOU RATES?

A. The Company is proposing to freeze the "Series 1" TOU rates to encourage participation in the Series 2 TOU rates and the new TOU rate proposal. The Company believes that the Series 2 TOU rates, due to the shorter on-peak period (and longer lower price off-peak periods), provide a better opportunity for customers to shift usage to the off-peak hours and, thereby, reduce their bills. This means that customers wishing to move to a TOU rate option would now

have the choice between the "Series 2" rates or the proposed TOU Schedule ET-SP.

C. General Service Rate Schedules

Q. WOULD YOU PLEASE DESCRIBE APS'S GENERAL SERVICE RATE SCHEDULES?

A. Yes. APS has eleven general service rate schedules. Commercial and industrial customers as well as those customers with specialized applications, are served under these schedules. There are six TOU rate schedules, one schedule for un-metered service, one schedule for athletic stadiums and arenas, a seasonal schedule, schedules for partial requirements service and schedules for dusk-to-dawn and street lighting services. There are two demand-based, non-TOU schedules. Approximately 95% of APS's general service customers are served on Rate Schedule E-32. Rate Schedule E-34 and TOU Rate Schedule E-35 are available for customers whose loads exceed three megawatts for three consecutive months during the year.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED CHANGES TO THE EXISTING GENERAL SERVICE RATE SCHEDULES?

A. Yes. The Company is proposing the following modifications to general service rate schedules:

- The basic service charges for all metered general service rate schedules were increased to better reflect the collection of costs associated with the customer being connected to APS's system. (*See* SFR Schedule H-3). These costs include metering, meter reading, billing, customer accounting and a small portion of fixed distribution costs.
- Schedule E-32 will be disaggregated into four new rate schedules.
- Schedule E-32TOU will also be disaggregated into four new rate

schedules.

- Partial requirement rate schedules E-32R, E-51 and E-55, which are currently frozen, will be cancelled.
- Schedules E-34 and E-35 were modified to equalize the treatment to equalize the treatment of military base customer served from dedicated feeders and to address special circumstances under which APS would incur additional third-party costs solely to serve a particular customer.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED MODIFICATIONS TO RATE SCHEDULE E-32?

A. Yes. As directed in Decision No. 69663, the Company is proposing to disaggregate rate schedule E-32 into several new rate schedules based on customer size. The current rate schedule has a separate rate structure and charges for customers in two size categories – Tier 1 (0-20 kW) and Tier 2 (greater than 20 kW). The proposed rate schedules will be divided into four groups of customers: E-32 XS (0-20 kW); E-32 S (21-100 kW); E-32 M (101-400 kW); and E-32 L (greater than 400 kW). The proposed rate structure for E-32 XS will be similar to the current E-32 less than 20 kW rate. The charges will be increased to produce revenue for this customer class that is better aligned with costs. The proposed rate structure for E-32 S, E-32 M, and E-32 L will be similar to the current E-32 greater than 20 kW rate. However, the charges will be adjusted to produce the designed revenue requirements for each customer category. The Company believes that this modification will provide rates that are better tailored to the customers in those size categories, and will result in revenues that are more aligned with costs. The proposed disaggregated Schedule E-32's are provided as Attachment GAD-5.

Q. WITH THE DISAGGREGATION OF E-32 INTO FOUR DIFFERENT RATE SCHEDULES, HOW WILL THE DETERMINATION BE MADE AS TO THE APPROPRIATE E-32 RATE SCHEDULE WHICH CUSTOMERS WILL BE SERVED?

A. Each year, the customers will be placed on the appropriate E-32 general service rate schedule based on the customer's average monthly billing kW over the six summer months (May – October). In the event that the customer's billing kW is not available for all six summer months, the determination will be made based on the best available information. For a new customer, the initial eligibility will be based on the estimated maximum kW as provided by the customer and approved by the Company. The placement of the customer on the appropriate E-32 general service rate schedule will occur in the February billing cycle following the annual determination. However, customers served on Schedule E-32 XS will not be re-assigned annually, but will be billed each month on either Schedule E-32 XS or E-32 S depending on their billing kW for the month. This deviation is appropriate because these customers may routinely be under or over 20 kW from month to month.

Q. HOW DOES THE COMPANY PROPOSE TO EASE IMPACTS ON CUSTOMERS RESULTING FROM THIS RATE STRUCTURE CHANGE?

A. Although APS has taken steps to disaggregate its E-32 as required by Decision No. 69663, and has developed rates that are more in line with the cost of service, the individual rate schedules have been designed to depart from strict cost of service adherence as necessary, so that differences in the increases that individual customers will experience will be moderated, while still moving the rates closer to cost of service. The Company will seek to further modify these

rate structures in future rate cases in an effort to continue to move toward more cost based rates.

Q. WHY IS THE COMPANY PROPOSING TO CANCEL PARTIAL REQUIREMENT RATE SCHEDULES E32-R, E-51, AND E-55?

A. In Decision No. 69663, the Commission ordered the Company to freeze partial requirement rate schedules E32-R, E-51, and E-55. The services provided under these rate schedules are now covered by Schedules E-56 and SC-S, both of which are more current partial requirements rates for customers with qualifying generators larger than 100 kW, and were approved by the Commission in Decision Nos. 70106 and 70130. Currently, there are two customers participating in Schedule E32-R, one in Schedule E-51, and one in Schedule E-55. Rate SC-S is more in line with the current Commission emphasis on supporting solar distributed generation. E-56 provides customers with more flexibility on how they can operate distributed generator units (including, but not limited to, renewable generation) and also reflects better pricing signals. The Company believes that these customers can migrate to Schedule E-56 and Schedule SC-S with minimal (if any) adverse impact on their bill.

D. General Service Time Of Use Rate Schedules

Q. WOULD YOU PLEASE GIVE A GENERAL DESCRIPTION OF APS'S CURRENT TIME-OF-USE RATES FOR GENERAL SERVICE CUSTOMERS?

A. The Company currently offers several time-of-use rates for general service and water pumping customers. Rate E-32 TOU is offered to general service customers with monthly demands less than 3 MW. Rate E-35 is available to customers with demands of 3 MW and above. These rates have an on-peak period of 11:00 a.m. to 9:00 p.m. weekdays, and are assessed energy and

demand charges for the on and off-peak periods. As of December 2007, 596 APS general service customers are participating in a TOU rate.

Q. HOW DOES THE COMPANY PROPOSE TO MODIFY ITS GENERAL SERVICE TOU PROGRAMS?

A. The Company is proposing to disaggregate Rate Schedule E-32 TOU into four separate rates for customers of various sizes: 0-20 kW; 21-100 kW; 101-400 kW; and greater that 400 kW. The Company believes that this modification will provide rates that are better tailored to the customers in those size categories and thereby improve the level of participation. In addition, the Company is proposing a critical peak price rate schedule for general service customers as described by Mr. Miessner.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED MODIFICATIONS TO RATE SCHEDULE E-32 TOU?

A. Yes. The Company is proposing to disaggregate rate schedule E-32 TOU into several new rate schedules based on the same customer size categories proposed for Rate Schedule E-32. The current rate schedule E-32 TOU is separated into two size categories – Tier 1 (0-20 kW) and Tier 2 (greater than 20 kW). The proposed rate schedules will be divided into four groups: E-32 TOU XS (0-20 kW); E-32 TOU S (21-100 kW); E-32 TOU M (101-400 kW); and E-32 TOU L (greater than 400 kW). The four new general service TOU rate schedules were designed using the same methodology and with the same objectives as previously described for E-32. The proposed E-32 TOU schedules are provided as Attachment GAD-6.

Q. HOW WILL THE DETERMINATION BE MADE AS TO THE APPROPRIATE E-32 TOU RATE SCHEDULE WHICH CUSTOMERS WILL BE PLACED?

A. The same process for determining the appropriate rate schedule for E-32 customers will be used for customers taking service under an E-32 TOU rate schedule.

Q. HOW DOES THE COMPANY PROPOSE TO EASE IMPACTS ON CUSTOMERS RESULTING FROM THIS RATE STRUCTURE CHANGE?

A. As with E-32, APS has taken steps to disaggregate its E-32 TOU as required by Decision No. 69663, and has developed rates that are more in line with the cost of service. The individual rate schedules have been designed to depart from strict cost of service adherence as necessary, so that differences in the increases that individual customers will experience will be moderated, while still moving the rates closer to cost of service. The Company will seek to further modify these rate structures in future rate cases in an effort to continue to move toward more cost based rates.

E. Schedules E-34 and E-35

Q. WOULD YOU PLEASE DESCRIBE THE CHANGES PROPOSED TO RATE SCHEDULES E-34 AND E-35?

A. Yes. Rate Schedules E-34 and E-35 are the rate schedules that are applicable to APS's largest customers. The basic service charge for both rate schedules has been increased to reflect cost of service. Based on cost of service, Rate Schedule E-34 customers will see a slightly lower class increase than the total Company requested increase. Likewise, Rate Schedule E-35 customers will see a slightly higher increase than the total Company requested increase. Language was added to both the E-34 and E-35 Schedules to broaden the application of the demand charge discount for military base customers taking primary service and served from a dedicated distribution feeder. This should result in both Luke

Air Force Base and the Yuma Marine Corps Air Station being served on the same footing with regard to their electric service.

Also, the Company added a provision to both rate schedules to require a customer to compensate the Company for the costs of additional third-party transmission service that is required solely to provide service to a specific customer or customers. This provision applies in those instances where the Company must enter into transmission arrangements for new or increased transmission service with a third party and those arrangements can be directly attributable to a specific customer or customers. The compensation includes third-party transmission wheeling costs, ancillary service costs, transmission facilities charges and line losses attributable to the third-party wheeling.

Q. WOULD YOU PLEASE DESCRIBE THE CHANGES PROPOSED TO RATE SCHEDULE E-36?

A. Yes. Rate Schedule E-36 is applicable to electric service for start-up and/or auxiliary load requirements for generation plants with a power supply capacity requirements of greater than 3 MW. The basic service charge has been decreased to reflect the fixed costs of service. In addition, the T & D Capacity Rate has been modified to reflect service voltage differences, and the transmission component of base rates has been removed from the delivery charge and included within the Company's proposed TCA.

F. Irrigation and Water Pumping

Q. WHAT ARE THE PROPOSED CHANGES TO IRRIGATION AND WATER PUMPING RATE SCHEDULES?

A. APS proposes to increase the overall charges under both irrigation and water pumping by an amount significantly lower than the total retail average increase based on cost of service data.

G. Street Lighting and Dusk to Dawn

Q. WHAT ARE THE PROPOSED CHANGES TO STREET LIGHTING AND DUSK TO DAWN LIGHTING RATE SCHEDULES?

A. APS proposes to increase the overall charges under both street lighting and dusk to dawn lighting by an amount significantly higher that the total retail average increase based on cost of service data.

H. Solar and Green Power Service Schedules

Q. DOES THE COMPANY PROPOSE TO MODIFY ANY OF ITS SOLAR OR GREEN POWER OFFERINGS?

A. Yes. The Company proposes to freeze Solar-2 to customers currently served under its terms. The Company believes that Solar-2 is no longer necessary since customers now have the option to participate in the Solar Partners Initiative Program and can receive an off-grid incentive by owning their own system. When Solar-2 was initially offered by the Company, the market and development of this technology was in its infancy. This resulted in few, if any, other options to customers wanting to utilize this technology. In addition, customer-owned photo-voltaic ("PV") systems today may be eligible for federal and state tax incentives not currently available to utilities. There are currently only two customers served on Solar-2.

In an effort to encourage greater customer participation in solar power, the Company proposes to offer customers two new subscription options of 10% and 35% to supplement the current 100% and 50% options on Schedule Solar-3.

The Company hopes these additional choices will increase customer participation in solar power for those that may not be able to otherwise participate through the REST. In addition, the Company has upgraded its billing system capability so that it can now offer customers the option to supplement energy usage by combining the Solar-3 and either green power service schedule (GPS-1 or GPS-2). Proposed Schedule Solar-3 is provided as Attachment GAD-7. By offering our customers the option of combining Solar-3 with green power service (GPS-1 and GPS-2), the Company can provide customers with even more flexibility to choose rates that fit their lifestyles. This ability to "mix and match" will hopefully increase participation in all three rate schedules.

The Company may also seek to modify its Green Power Service Schedules 1 and 2 (in accordance with their terms) in a separate proceeding later this year. Therefore, the Company is not proposing any change to these two schedules within this case, other than as mentioned above, to offer customers the option to supplement its energy usage from a combination of Solar-3 and green power service schedules.

I. Critical Peak Pricing

Q. IN THE LAST RATE CASE, THE COMMISSION ENCOURAGED THE COMPANY TO LOOK AT CRITICAL PEAK PRICING AND TO PROPOSE THIS TYPE OF PRICING STRATEGY IN ITS NEXT RATE APPLICATION. IS APS PROPOSING ANY CRITICAL PEAK PRICING RATE OPTIONS IN THIS CASE?

A. Yes, and Mr. Miessner describes the Company's proposal in his testimony. However, APS believes its proposed introduction of a "super peak" TOU option for customers is very analogous to critical peak pricing proposals in other jurisdictions and may result in the same or similar impact on peak load.

Q. WOULD THE COMPANY BE ABLE TO IMPLEMENT ALL OF THE PROPOSED RATE CHANGES IMMEDIATELY AFTER RECEIVING COMMISSION APPROVAL?

A. The Company is planning for the necessary changes to customer billing, metering and related systems required to implement the proposed changes to the rate schedules discussed in my testimony. However, the super peak and critical peak pricing options discussed by Mr. Miessner will require additional time to implement after an order is received in this proceeding to accommodate the required billing, metering, training, customer service and related systems. These implementation issues are discussed in more detail by Mr. Miessner.

J. Other Miscellaneous Rate Modifications

Q. ARE THERE ANY OTHER RATE MODIFICATIONS PROPOSED BY THE COMPANY?

A. Yes. As previously mentioned, the Company proposes to roll into base rates the increased base fuel amount as supported by APS Witness Peter Ewen. Base rates will incorporate a base fuel amount of 3.88¢/kWh, an increase from 3.25¢/kWh. Also, base rates will no longer have the Transmission Charge listed separately in each individual rate schedule. All transmission costs will be recovered by the TCA as discussed in the testimony of Mr. Rumolo.

VI. PARTIAL REQUIREMENTS SERVICE

A. Schedule EPR-5 Partial Requirements Service (Net Metering)

Q. IN DECISION NO. 69663, THE COMMISSION AUTHORIZED THE COMPANY TO DEFER AND SEEK RECOVERY OF UNCOLLECTED FIXED COSTS IN ITS NEXT RATE CASE. IS THE COMPANY REQUESTING COLLECTION OF THESE COSTS IN THIS CASE?

A. No. Due to the minimal time that has transpired since approval of Schedule EPR-5 (July 1, 2007) and the end of the Test Year for this rate case (December

31, 2007), there has been minimal customer participation in EPR-5, and, therefore, the calculation of uncollected fixed costs (as defined by Decision No. 69663) would also be minimal at this time. Second, pursuant to Decision No. 69663, the Company is continuing its study of the cost and benefits of renewable distributed generation on the system and until more information is ascertained on the costs and benefits of renewable distributed generation, the Company will continue to defer these costs and seek their recovery at a later time. The Commission is in the process of a rulemaking on net metering that could potentially expand the application and, therefore, significantly increase future uncollected fixed costs.

B. Schedule EPR-2 Partial Requirements Service (Net Billing)

Q. DOES THE COMPANY PROPOSE TO MODIFY EPR-2?

A. Yes. The Company has modified EPR-2 purchase rates to reflect updated avoided cost numbers. The purchase rates have been further refined and indicated by defined on-peak/off-peak periods, season and level of firmness. The on-peak/off-peak purchase price has been segregated by TOU periods of 9 a.m.-9 p.m., Noon-7 p.m. and 11 a.m.-9 p.m. weekdays.

VII. SERVICE SCHEDULES

A. Schedule 1 - General Terms And Conditions

Q. IS APS PROPOSING REVISIONS TO SERVICE SCHEDULE 1?

A. Yes. APS is continually evaluating all aspects of its service schedules to enhance the Company's business practices. As part of this review, APS is proposing certain revisions. These changes are being proposed to add clarifying language that better reflects the Company's anticipated business practices. A redline copy of the schedule is attached as Attachment GAD-8.

Q. PLEASE DESCRIBE THE SIGNIFICANT CHANGES TO SCHEDULE 1.

A. Sections 2.5.1 and 2.5.1.5: APS is proposing additional language to Section 2.5.1 and the addition of Section 2.5.1.5 to specify that the Company will require a security deposit from an applicant when the applicant currently has or is requesting service at more than 2 residences. The Company proposes this language to reduce the potential financial risk to APS and its other customers from those that have more than two residential accounts and may default on payment of electric bills to one or all of such accounts. The Company believes that this change is required given the status of the current residential real estate market in which speculators often own many residences.

Section 2.7.6: APS is proposing additional language to Section 2.7.6 which provides for security deposits not to exceed "the higher amount of either: one (1) time the customer's maximum monthly bill; or two (2) times the customer's average monthly bill as estimated by Company for the services being provided by Company." The language provides APS the ability to secure a larger deposit for those instances when a customer's bill (in particular in the summer months) is higher than twice the customer's average. APS realizes this is a variance to a Commission rule enacted many years ago, but one that likely reflected a time when peak monthly bills were closer to the average monthly bill than is presently the case.

Section 4.3.2: APS is proposing additional language to Section 4.3.2 which refers to the applicability of APS's Service Schedule 8 when bill estimation is required.

Section 5.4: APS is proposing additional language to Section 5.4 requiring 24-hour access to APS's equipment located on the customer's site for the purposes of repair, maintenance, or service restoration work.

Section 6.1: APS is proposing clarifying language to Section 6.1. There are certain circumstances (*e.g.* for some tribal areas, governmental buildings or projects, etc.) where the applicable inspection agency (County or City) deems that a City or County inspection ("clearance" or "green tag") is not necessary. This is usually because the customer is exempt from such requirements for some obscure reason(s). In such cases, a Letter In-Lieu of Electrical Clearance is required by APS that indicates the customer wiring/electrical facilities have been installed per code.

Section 6.4.2: APS is proposing clarifying language to Section 6.4.2 to address circumstances in which people disconnect service but continue to use service until they move out.

Section 6.6.3: APS is proposing clarifying language to Section 6.6.3 to make it consistent with Schedule 3 language.

Sections 7.2.5 and 7.2.6: APS is proposing to add Sections 7.2.5 and 7.2.6 to address circumstances in which customers make payments to avoid or stop non-payment disconnection or pay for reconnection service with a dishonored payment. Under these circumstances, APS would require repayment of all costs associated with the dishonored payment as well as all other delinquent amounts prior to reconnection.

Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 1?

A. Yes, there are some additional minor changes that are being proposed for clarity purposes only and have no material impact on customers.

B. Schedule 4 – Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service

Q. IS APS PROPOSING REVISIONS TO SERVICE SCHEDULE 4?

A. Yes. Changes are being proposed to discourage customer switching back and forth between different rates or billing plans, as discussed below, and to add clarifying language that reflects the Company's anticipated business practices. A redline copy of the schedule is attached as Attachment GAD-9.

Q. PLEASE DESCRIBE THE SIGNIFICANT CHANGES TO SCHEDULE 4.

A. Section A.8: APS is proposing to add Sections A.8, D.4, and D5. These sections were added to discourage customers from moving back and forth between totalized and non-totalized accounts to essentially arbitrage the seasonal rates associated with non-totalized accounts.

Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 4?

A. Yes, there are some additional minor changes that are being proposed for clarity purposes.

C. Schedule 5 – Guidelines for Electric Curtailment

Q. WHY IS APS PROPOSING REVISIONS TO SERVICE SCHEDULE 5?

A. APS is proposing changes to Schedule 5 to add clarifying language that better reflects our envisioned business practices. A redline copy of the schedule is attached as Attachment GAD-10.

Q. PLEASE DESCRIBE THE SIGNIFICANT CHANGES TO SCHEDULE 5.

A. Section 5.1.1.11: APS is proposing to add Section 5.1.1.11. This section was added to encourage expediting the permitting process for company-owned generation by working with government agencies and environmental groups to seek waivers on environmental constraints during curtailment situations.

Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 5?

A. No.

D. Schedule 8 – Bill Estimation

Q. IS APS PROPOSING REVISIONS TO SERVICE SCHEDULE 8?

A. Yes. The changes that are being proposed include bill estimation procedures for partial requirements and net metering customers and add clarifying language that better reflects the Company's envisioned business practices. These partial requirements customers were not specifically addressed when Schedule 8 was first approved by the Commission. A redline copy of the schedule is attached as Attachment GAD-11.

Q. PLEASE DESCRIBE THE SIGNIFICANT CHANGES TO SCHEDULE 8.

A. Section 3.1: APS is proposing to add clarifying language to Section 3.1. Additional language was added to make this section applicable for energy estimation for customers with on-site generation taking service under Rate Schedules EPR-2 and EPR-5.

Section 3.1.1: APS is proposing clarifying language to Section 3.1.1. Additional language was added to include applicable seasonal percentages when estimating customer-owned on-site distributed generation.

Section 3.1.2: APS is proposing to add Section 3.1.2. This section was added to describe energy estimation procedures for customer-owned on-site distributed generators (partial requirements customers). This process is similar to that approved in Section 3.1 (Energy Estimation).

Section 3.2.8: APS is proposing to add Section 3.2.8. This section was added to describe demand estimation procedures for customer-owned on-site distributed generators (partial requirements customers). This process is similar to that approved in Section 3.2.1 through 3.2.4 (Demand Estimation).

Section 3.3.1: APS is proposing clarifying language to Section 3.3.1. Additional language was added to include applicable minimum usage estimates for customer-owned on-site distributed generation customers.

Section 3.5: APS is proposing clarifying language to Section 3.5. Additional language was added to address estimating customer-owned on-site generation bought by APS.

Q. ARE YOU REQUESTING ANY OTHER SUBSTANTIAL CHANGES TO SCHEDULE 8?

A. No.

E. Schedule 10 – Terms and Conditions for Direct Access

Q. IS APS PROPOSING REVISIONS TO SERVICE SCHEDULE 10?

A. Yes. A redline copy of the schedule is attached as Attachment GAD-12.

Q. PLEASE DESCRIBE THE SIGNIFICANT CHANGES TO SCHEDULE 10.

A. Section 8.2.1: APS is proposing additional language that will allow the ESP to subcontract with the Utility Distribution Company for both metering and meter reading services to minimize the potential stranding of the Company's embedded metering costs, especially AMI meters.

Q. WILL ESP'S STILL BE ABLE TO PROVIDE THIS SERVICE?

A. Yes. While the Company would have the ability to provide metering and meter reading, it would not restrict a meter service provider from providing such service to an ESP, if the ESP elected to receive such services from a non-APS provider.

Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 10?

A. Yes. There are some additional minor changes that are being proposed for clarity purposes only and have no significant impact on customers.

F. Schedule 15 – Conditions for Governing the Provision of Specialized Metering

Q. IS APS PROPOSING REVISIONS TO SERVICE SCHEDULE 15?

A. Yes. A redline copy of the schedule is attached as Attachment GAD-13.

Q. PLEASE DESCRIBE THE SIGNIFICANT CHANGES TO SCHEDULE 15.

A. Section 1: APS is proposing to delete a provision requiring the customer to specify if a modem is needed. Because APS has more familiarity with its metering needs and products, the Company is in a better position to determine whether a modem is needed. The customer may still request a modem, but APS would ultimately make the final decision based on availability of meters, the type of meter requested, and cost.

Section 2: Due to advancements in technology, APS is currently installing Telco interface boxes that already include the appropriate jack. Requiring customer installation within five feet will ensure enough cable for proper installation. Additional language requiring meter location was added to ensure proper access to metering equipment.

Section 3: APS is now providing customer pulse interface. Changes made to this section reflect a shift in business practices. An isolation relay is no longer needed because new solid state equipment provides the needed isolation.

Sections 5 and 7: APS is proposing clarifying language to Sections 5 and 7. The wording in these sections was changed to reflect the advancement in technology and the usage of the solid state equipment mentioned in Section 3 above.

Section 13: APS is proposing a wording change by replacing the terms "isolation relay" and replacing it with "KYZ" relay to reflect the advancement in technology and to be consistent with the proposed changes recommended to Sections 3, 5, and 7 above.

Q. ARE YOU REQUESTING ANY OTHER CHANGES TO SCHEDULE 15?

A. Yes. There are some additional minor changes that are being proposed for clarity purposes only and have no significant impact on customers.

Q. HAVE YOU ATTACHED ALL OF THE COMPANY'S PROPOSED RATE SCHEDULES TO YOUR TESTIMONY?

A. No. For ease of review, the Company has attached all of its rate schedules, whether modified or not, to this Rate Application. However, only Service

Schedules 1, 2, 4, 5, 8, 10 and 15, rate schedules E-32 and E-32 TOU and adjustment schedules EIS and DSMAC are attached to my testimony.

VIII. CONCLUSION

Q. WOULD PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. The Company requests that the Commission modify the EIS by allowing the Company to recover additional actual costs of environmental improvement projects and implement an adjustor mechanism to allow modification of the EIS charge on an annual basis, modify the DSM adjustor through the DSMAC to allow a more timely and predictable recovery of prudently incurred DSM program costs as well as to provide enhanced incentives to encourage the development of efficient programs, and provide for the recovery of unrecovered fixed costs.

The Commission should likewise approve the rate schedules as proposed herein and also: (1) freeze the "Series 1" TOU rates; (2) modify E-12 to include the addition of a fourth higher priced block rate; (3) disaggregate Schedule E-32 and E-32TOU into four new rate schedules; (4) cancel partial requirement rate schedules E-32R, E-51 and E-55; (5) freeze Solar-2; (6) add 10% and 35% subscription options to Schedule Solar-3 and permit multiple subscriptions to Solar 3, GP-1 and GP-2; (7) modify Service Schedules 1, 4, 5, 8, 10 and 15; and (8) authorize the Company, under Schedule EPR-5, to continue deferring certain uncollected fixed costs for its net metering program and to seek their recovery in a subsequent rate proceeding.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

APPENDIX A

Statement of Qualifications for Gregory A. DeLizio

Gregory A. DeLizio is Arizona Public Service Company's Manager of Pricing. He has over 27 of years experience in the electric utility business. Mr. DeLizio holds a Bachelor of Science Degree in Electrical Engineering from the University of Pittsburgh and a Masters in Business Administration from Kent State University.

Mr. DeLizio has submitted testimony before the Arizona Corporation Commission, the Public Utilities Commission of Ohio, the Public Service Commission of West Virginia, the Michigan Public Service Commission, the Indiana Utility Regulatory Commission and the Oklahoma Corporation Commission. Mr. DeLizio is experienced in the areas of electric utility rate design, embedded and marginal cost analysis, utility service policies, and contract development and negotiation.

Mr. DeLizio was employed in his current position at Arizona Public Service Company in August of 2005. Prior to assuming this position, he served as Managing Director – Regulated Pricing and Analysis for American Electric Power Service Corporation, a wholly-owned subsidiary of American Electric Power Company (AEP). In this position, Mr. DeLizio's responsibilities included setting regulated pricing policy, supervision of the preparation of class cost of service studies, rate design and unbundled rates and provisions, and special contracts and pricing of retail customers for AEP's eleven operating companies operating in 14 states. Mr. DeLizio held positions of increasing responsibilities at AEP starting in 1981 when he joined Ohio Power Company (an AEP operating subsidiary) as an Energy Services Engineer. He was promoted to Power Engineer in 1984, promoted to Energy Services Coordinator in 1985, promoted to Load Research Supervisor in 1987, Marketing & Customer Services Supervisor in 1992, Special Contracts Administrator in 1993, Regulatory Consultant in 1996 and to Manager – Regulated Pricing & Analysis in 2000.

SCHEDULE EIS
ENVIRONMENTAL IMPROVEMENT SURCHARGE

APPLICATION

The Environmental Improvement Surcharge ("EIS") shall apply to all retail Standard Offer service, excluding kWh served in accordance with solar rates SP-1 (Solar Partners), Solar-2, and Green Power Schedules GPS-1 and GPS-2. All provisions of the customer's current applicable rate schedule shall apply in addition to charges under this Adjustment Schedule EIS.

The EIS was approved by the Arizona Corporation Commission ("ACC") in Decision No. xxxxx~~69663~~.

The EIS recovers the cost associated with investment and expenses for environmental improvements at APS' generation facilities that the ACC has approved for recovery. Approved environmental improvements include those implemented on or after January 1, 2004, for which costs have not been fully recovered under current approved rates, ongoing environmental improvement projects and environmental improvement projects designed to comply with prospective environmental standards required by federal, state, tribal, or local laws or regulations.

RATE

The charge shall be calculated at the following rate:

EIS

All kWh	$0.00016 per kWh

APS

SCHEDULE EIS
ENVIRONMENTAL IMPROVEMENT SURCHARGE
PLAN OF ADMINISTRATION

EIS PLAN OF ADMINISTRATION

The Environmental Improvement Surcharge ("EIS") Schedule recovers the cost associated with investment and expenses for environmental improvements. As authorized by the Arizona Corporation Commission ("ACC") this Schedule allows for timely recovery of costs as environmental investments are made.

DETERMINATION OF EIS

The EIS will be determined in accordance with the following:

1. The initial EIS was established in Decision No. 69663, issued on June 28, 2007.

2. The EIS will include all Revenue Requirement components including, but not limited to return on capital, depreciation, operation and maintenance expenses, property taxes, and associated income taxes as shown on Schedule 2.

3. The EIS recovers the cost associated with investment and expenses for environmental improvements at generation facilities that the ACC has approved for recovery. Approved environmental improvements include those implemented on or after January 1, 2004, for which costs have not been fully recovered under current approved rates, pursuant to Decision No. 70213. Environmental improvement projects or prospective environmental improvement projects are projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations.

4. The EIS for bills rendered April 1 through March 31 of each year will be computed based on the Revenue Requirement for actual investment of environmental projects not closed to plant-in-service prior to December 31 of the previous year. Investments in environmental projects placed in rate base pursuant to Decision No. _____ will be excluded. The EIS will use the retail sales forecast for the period in which bills will be rendered.

5. APS will submit to the Commission the proposed EIS by February 28th of each year for Utility Division Commission Staff ("Staff") and interested parties review. Unless otherwise acted upon by the Commission, changes in the EIS will be effective each year beginning with billing cycle one of the April revenue month and will not be prorated. The projects included in the EIS calculation will submitted, as shown on Schedule 1, and the calculation of the proposed EIS as shown on Schedule 2.

6. The applicable $/kWh Charge is constant and applies in each month of the Billing Period for which it is calculated. The rate calculation considers actual amount of environmental expenditures (excluding fines or penalties), APS' forecasted sales and the revenue resulting from such application of the EIS plus a true-up of any over or under recovery for prior periods Revenue Requirements.

7. Any over or under collection made as part of the true-up process under the EIS will include interest equal to the Company's ACC most recently authorized Average Weighted Cost of Capital (WACC). The account balance and any over or under collection, with interest, for each year, will be submitted to the Commission with the proposed EIS by February 28th of each year as shown on Schedule 3.

8. The EIS will be applied to all retail Standard Offer customers kWh usage except those kWh subscribed to under Schedules SP-1, Solar-2, Solar-3, GPS-1 and GPS-2.

9. At the time rates in the subsequent rate case are approved, the EIS will be adjusted to reflect plant and expenses that are incorporated into rate base for the test year.

10. The EIS Surcharge will appear on customer bills as the "Environmental Improvement Surcharge." The informative description on the bill will state, "A charge to recover a portion of the cost of

APS

SCHEDULE EIS
ENVIRONMENTAL IMPROVEMENT SURCHARGE
PLAN OF ADMINISTRATION

investments for environmental improvements at APS' generation facilities designed to comply with environmental standards mandated or expected to be mandated by federal, state or local laws or regulations."

Schedule 1

ARIZONA PUBLIC SERVICE COMPANY
Environmental Improvement Surcharge
Project Expenses (Example)

Projects	Year 1	Year 2	Year 3	Year 4	Year 5	Total	In-Service Date
Project A	$xxxxxx	$xxxxxx	$xxxxxx	-	-	$ xxxxxx	xx/xx/xxxx
Project B	-	$xxxxxx	$xxxxxx	-	-	$ xxxxxx	xx/xx/xxxx
Project C	-	-	$xxxxxx	$xxxxxx	-	$ xxxxxx	xx/xx/xxxx
Project D	-	-	$xxxxxx	$xxxxxx	-	$ xxxxxx	
Project E	-	-	$xxxxxx	$xxxxxx	$xxxxxx	$ xxxxxx	
Project F	-	-	$xxxxxx	$xxxxxx	$xxxxxx	$ xxxxxx	
.						.	
.						.	
.						.	
						.	
Total Project Expenses	$xxxxxx	$xxxxxx	$xxxxxx	$ xxxxxx	$xxxxxx	$xxxxxx	

Schedule 2

ARIZONA PUBLIC SERVICE COMPANY
Environmental Improvement Surcharge
Revenue Requirement Calculation (Example)

Capital Investment Period Ending: xx/xx/xxxx
Billing Period: xx/xx/xxxx-xx/xx/xxxx
($000s)

Line		
0	Balance from Schedule 3 (Line 6: Total)	$xxxxxx
1	Beginning Balance of CWIP	$xxxxxx
2	Additions of Environmental Capital Expenditures	$xxxxxx
3	Closed to Plant in Service	$xxxxxx
4 = 1+2-3	Ending Balance of CWIP	$xxxxxx
5	Cumulative Gross Plant in Service	$xxxxxx
6	Accumulated Depreciation	$xxxxxx
7 = 5-6	Net Plant in Service	$xxxxxx
8	Cumulative Deferred Tax	$xxxxxx
9 = 7-8	Net Plant in Service	$xxxxxx
10 = 4+9	*Sum of CWIP and Environmental Capital Improvements*	$xxxxxx
11	Weighted avg debt rate	x.xxxx%
12	Pre-tax weighted avg equity rate	x.xxxx%
13 = 11+12	Composite Rate of Return	x.xxxx%
	Revenue Requirement	
14 = 10 x 13	Composite Return on CWIP and Environmental Capital Improvements	$xxxxxx
15 = 5	Cumulative Annual Depreciation of Plant in Service	$xxxxxx
16	O&M	$xxxxxx
17 = 14+15+16+0	**Total EIS Revenue Requirement**	**$xxxxxx**
18	**Retail MWH Forecast: xx/xx/xxxx to xx/xx/xxxx**	$xxxxxx
19 = 17/18	**EIS ($/kWh)**	**x.xxxxx**

Schedule 3

ARIZONA PUBLIC SERVICE COMPANY
Environmental Improvement Surcharge
Account Balance (Example)
Billing Period: xx/xx/xxxx to xx/xx/xxxx

Line No.		April	May	June	July	August	September	October	November	December	January	February	March	Total
1	Surcharge	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx	x.xxxxx
2	Month beginning Revenue Requirement Balance (Line 7 of Previous Month)	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx
3	Actual Revenue Collected thru Surcharge	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx
4	Revenue Requirement per EIS POA	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx
5	Revenue Over/(Under) Collected (Line 2 - Line 3 + Line 4)	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx
**6	Monthly Interest (Line 5 * [Interest Rate/12])	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx
7	Month Ending Revenue Requirement Including Interest (Line 5 + Line 6)	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx	$xxxxx

** Based on CWIP and Environmental Capital Improvements pre tax weighted average cost of capital

Balance (Example)

ADJUSTMENT SCHEDULE DSMAC-1
DEMAND SIDE MANAGEMENT ADJUSTMENT

APPLICATION

The Demand Side Management Adjustment Charge ("DSMAC") shall be applied monthly to every metered and/or non-metered retail Standard Offer or Direct Access -service~~ with the exception of solar rates Solar-1, Solar-2 and SP-1.~~ –All provisions of the customer's currently applicable rate schedule will apply in addition to this adjustment charge. The DSMAC is applied to Standard Offer or Direct Access customer's bills as monthly charge to recover the cost of Commission approved demand side management programs above those costs included in base rates. The DSMAC will be changed in billing cycle 1 of the ~~March~~ April revenue month and will not be prorated. The DSMAC and the EPS Surcharge adjustor may be combined on the customer's bill and appear on the "Environmental Benefits Surcharge" line. Details of how the DSMAC is derived and administered can be found in the Demand Side Management Adjustment Charge Plan for Administration.

RATE

The charge shall be calculated at the following rate:

For all residential customers and general service customers whose billing does not include demand charges:

All kWh	$0.000000	per kWh

For general service customers whose billing includes demand charges:

All metered kW	$0.000000	per kW

ADJUSTMENT SCHEDULE DSMAC-1
DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE
PLAN OF ADMINISTRATION

I. GENERAL DESCRIPTION:

Eligible Demand Side Management ("DSM") related items include energy-efficiency DSM programs; demand response DSM programs, a performance incentive; unrecovered fixed costs, low income bill assistance and any other costs authorized by the Arizona Corporation Commission ("Commission" or "ACC"). The Demand-Side Management Adjustment Charge ("DSMAC") charge is applied to Standard Offer or Direct Access customer's bills as a monthly kilowatthour (for customers served in accordance with non-demand metered rate schedules) or kilowatt demand charge (for customers served in accordance with demand metered rate schedules). The charge will be recomputed annually and filed with the Commission by February 28th for Utility Division Commission Staff ("Staff") and interested parties review. Unless otherwise acted upon by the Commission, the charge will be effective each year beginning with billing cycle 1 of the April revenue month and will not be prorated.

Recovery of all applicable programs costs/incentives will be allowed for all programs that have been approved by the ACC or are pending for approval by the ACC. The DSMAC will recover: (1) all costs associated with energy-efficient DSM programs and demand response DSM programs in excess of the amount recovered through base rates (currently $10 million); (2) all unrecovered fixed costs; and (3) performance incentives.

II. ALLOWABLE COSTS:

The types of allowable costs are as follows:

A. Program Costs (PC)	Allowable expenses will include, but not be limited to : program development, implementation, promotion, administrative and general, monitoring/metering costs, advertising, educational expenditures, incentives, research and development, data collection (such as end-use), tracking systems, measurement evaluation reporting (MER), demonstration facilities and all other activities required to design and implement cost effective DSM Programs (energy efficiency and demand response) that are approved or are pending approval by the Commission. For those DSM programs that generate revenue, the revenue, if any, will be credited back to the DSMAC. Program Costs as described herein for the next Adjustor Period are reduced by $10 million collected through base rates.
B. Unrecovered Fixed Costs (UFC)	Represents total estimated annual lost revenues associated with fixed costs between rate cases, resulting from reduced sales as a consequence of conservation measures implemented under the auspices of the DSM Program, net of any system savings (fuel costs, variable O&M, etc.) realized because of reduced sales.
C. Performance Incentives (PI)	Represents a 10% share of the net economic benefits (benefits minus costs) from approved and pending energy-efficiency and demand response programs.

APS

ADJUSTMENT SCHEDULE DSMAC-1
DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE
PLAN OF ADMINISTRATION

III. DETERMINATION OF TRUE-UP BALANCE:

The actual allowable cost less the $10 million recovered annually in rate base for approved DSM programs will be compared to the actual revenues received by the Company through imposition of the Adjustor on customer bills. The True-Up Balance (TUB) will be based on calendar year actual Allowable Costs and DSMAC revenue collection. The Reconciliation Schedule for the Balancing Account (Schedule 1) will be provided annually.

In the event that APS spends more or less than DSMAC revenues collected in a given year on pre-approved projects or those pending approval, the under collection/over collection plus interest will be applied to subsequent years' adjustor amounts.

The Reconciliation Schedule will be filed by February 28th of each year. Any amounts remaining in the balancing account due to over/under recovery will be used in calculating the Adjustment Charge for the next Adjustor Period.

IV. DETERMINATION OF ADJUSTOR FACTOR:

Before or on February 28th of each calendar year, the Company will file a revised DSMAC with supporting documentation. Schedule 2 will list all programs currently approved and pending under the DSM Program and calendar year budget for each program. Schedule 2 will be updated/revised on an annual basis. The DSMAC will be recomputed annually on Schedule 3.

The annual Adjustor Charge will be calculated based on the aggregate costs of approved and pending programs for the Adjustor period minus $10 million recovered in base rates. Any over / under recovery of revenues resulting from specific program additions or deletion or findings from program monitoring will be accumulated in the Balancing Account for resolution during the next subsequent annual calculation of the DSMAC pursuant to Section III.

An Adjustor Charge for purposes of recovering Allowable Costs under the DSM Program will be developed based on the following formula:

$$\text{Adjustor Charge} = \frac{(PC + UFC + PI) + TUB + i}{\text{Sales}}$$

Where:

TUB = Any "true-up" balance that has accumulated as of December 31st of the previous year. Section III of this Plan of Administration outlines procedures for administering the true-up balance.

i = Interest associated on any over or under recovery of DSMAC costs for the prior period. The interest rate is based on the one-year Nominal Treasury Maturities rate from the Federal Reserve H-15 or its successor publication.

Sales = Forecast sales under applicable electric rate schedules during the Adjustor Period in which this Adjustor will be effective.

APS

ADJUSTMENT SCHEDULE DSMAC-1
DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE
PLAN OF ADMINISTRATION

Adjustor Period = The 12 month period beginning with the first billing cycle during April of the current year and ending with the last billing cycle of March of the next year.

General Service customers that are demand billed will pay a per kW charge instead of a per kWh charge. General Service customers that are not demand billed shall pay the DSMAC on a per kWh basis. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSMAC.

Each historic cost period and budget period will be calendar year unless required to be adjusted due to a rate case filing.

VI. REVIEW PROCESS:

The proposed Adjustor Charge for use during a specific Adjustor Period will be calculated as shown on Schedule 3. The Company's estimate of the applicable Adjustor Charge for the subsequent Adjustor Period will be submitted for Staff and interested parties review by February 28th of each year. Unless otherwise acted upon by the Commission, changes in the Adjustor Charge will go into effect on the first billing cycle each April revenue month.

VII. RATE SCHEDULE APPLICABILITY:

The DSMAC shall be applied monthly to every retail Standard Offer or Direct Access service.

Pursuant to Decision No. 67744, any customer who can demonstrate as active DSM program and whose single site usage is twenty MW or greater may file a petition with the Commission for exemption from the DSM adjustor. The public shall have 20 days to comment on such petition. In considering any petition pursuant to this paragraph, the Commission may consider the comments received and any other information that is relevant to the customer's request.

Schedule 1
Balancing Account

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

Year Ending _____
BALANCING ACCOUNT

Line No.		Amount
1	Beginning Period Balancing Account as of December 31,20yy	$
2	Demand Side Management Adjustor Charge Revenues collected	$
3	Net Allowable Cost (Schedule 2)	$
4	Year ending Over/(Under) Recovery (Line 2 - Line 3)	$
5	Interest on Over/(Under) Recovery	$
6	Ending Period Balance (Line 1 + Line 4 + Line 5)	$

Schedule 2
BUDGET

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

CALENDAR ESTIMATED BUDGET FOR ALLOWANCE COSTS
FOR THE ADJUSTOR PERIOD [1]
($000)

Program	Program Costs		Uncollected Fixed Costs		Total
Program 1	$		$		$
Program 2	$		$		$
Program 3	$		$		$
Program 4	$		$		$
Program 5	$		$		$
Program 6	$		$		$
Program 7	$		$		$
Total	$		$		$
Incentive Amount					$
Measurement Evaluation Reporting (MER)					$
Base Rate Amount					$ (10,000)
Net Allowable Cost					$

[1] Reflects estimated Program Costs, Uncollected Fixed Costs and Incentive Amounts for the Period January 1, 20yy through December 31, 20yy

Schedule 3
Adjustor Calculation

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

Calculation of DSM Adjustor Charge for the Period
January 1, 20yy through December 31, 20yy

Line No.			
1	Ending Balance from Schedule 1 as of 12/31/20yy	$	
2	Net Allowable Costs (Schedule 2) for next year January 1, 20yy through December 31, 20yy	$	
3	Total Amount to be Collected (Line 1 + Line 2)	$	
4	Forecast retail kWh Sales for next year period April 1, 20yy through March 31, 20yy		
5	Proposed Adjustor Charge (Line 3 / Line 4) for next year period April 1, 20yy through March 31, 20yy	$	$/kWh charge for all residential customers and general service customers whose billing does not include demand charges
6	Forecast General Service billing demand metered customer kWh sales for next year period April 1, 20yy through March 31, 20yy		
7	Amount to be collected from General Service billing demand metered customer for next year period April 1, 20yy through March 31,20yy (Line 5 x Line 6)	$	
8	Forecast General Service billing demand metered customer kW for next year period April 1, 20yy through March 31, 20yy		
9	Proposed Adjustor Charge (Line 7 / Line 8) for next year period April 1, 20yy through March 31, 20yy	$	$/kW charge for general service customers whose billing includes demand charges

RATE SCHEDULE E-32 XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is 20 kW per month or less.

The Company initially will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company.

The Customer will be billed on Schedule E-32 S or E-32 XS depending on the Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$	0.591	per day, or
For service through Instrument-Rated Meters:	$	1.150	per day, or
For service at Primary Voltage:	$	2.942	per day

RATE SCHEDULE E-32 XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)

RATES (cont)

Bundled Standard Offer Service (cont)

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
For Secondary Service: $0.13539 per kWh for the first 5,000 kWh, plus $0.07630 per kWh for all additional kWh, or	For Secondary Service: $0.11376 per kWh for the first 5,000 kWh, plus $0.05467 per kWh for all additional kWh, or
For Primary Service: $0.11439 per kWh for the first 5,000 kWh, plus $0.07070 per kWh for all additional kWh	For Primary Service: $0.10816 per kWh for the first 5,000 kWh, plus $0.04907 per kWh for all additional kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.124	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.345	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary:	$ 2.696	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00188	per kWh

APS

RATE SCHEDULE E-32 XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
For Secondary Service: $0.02773 per kWh for the first 5,000 kWh, plus $0.00837 per kWh for all additional kWh, or	For Secondary Service: $0.02767 per kWh for the first 5,000 kWh, plus $0.00831 per kWh for all additional kWh, or
For Primary Service: $0.00673 per kWh for the first 5,000 kWh, plus $0.00277 per kWh for all additional kWh	For Primary Service: $0.02207 per kWh for the first 5,000 kWh, plus $0.00271 per kWh for all additional kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10578 per kWh for the first 5,000 kWh, plus $0.06605 per kWh for all additional kWh	$0.08421 per kWh for the first 5,000 kWh, plus $0.04448 per kWh for all additional kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

MINIMUM

The bill for Standard Offer and Direct Access customers will not be less than the applicable Bundled Standard Offer Service Basic Service charge.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment. Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

RATE SCHEDULE E-32 XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. xxxxx.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands up to 20 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

RATE SCHEDULE E-32 XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32 S
SMALL GENERAL SERVICE (21 kW – 100 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 20 kW and less than or equal to 100 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination.

The Customer will be billed on Schedule E-32 S or E-32 XS depending on the Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 1.068	per day, or
For service through Instrument-Rated Meters:	$ 1.627	per day, or
For service at Primary Voltage:	$ 3.419	per day

APS

RATE SCHEDULE E-32 S
SMALL GENERAL SERVICE (21 kW – 100 kW)

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 7.557	per kW for the first 100 kW, plus
	$ 3.801	per kW for all additional kW, or
Primary Service:	$ 5.892	per kW for the first 100 kW, plus
	$ 2.136	per kW for all additional kW, or

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10879 per kWh for the first 200 kWh per kW, plus $0.06346 per kWh for all additional kWh	$0.09080 per kWh for the first 200 kWh per kW, plus $0.04548 per kWh for all additional kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.601	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.345	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary:	$ 2.696	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00188	per kWh
Delivery Charge:		
Secondary Service:	$ 7.557	per kW for the first 100 kW, plus
	$ 3.801	per kW for all additional kW, plus
	$ 0.00010	per kWh, or

APS

RATE SCHEDULE E-32 S
SMALL GENERAL SERVICE (21 kW – 100 kW)

RATES (cont)

Unbundled Standard Offer Service (cont)

Primary Service:	$ 5.892	per kW for the first 100 kW, plus
	$ 2.136	per kW for all additional kW, plus
	$ 0.00010	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10681 per kWh for the first 200 kWh per kW, plus $0.06148 per kWh for all additional kWh	$0.08882 per kWh for the first 200 kWh per kW, plus $0.04350 per kWh for all additional kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

MINIMUM

The bill for Standard Offer and Direct Access customers will not be less than the applicable Bundled Standard Offer Service Basic Service charge plus $2.094 for each kW of either: (1) the highest kW established during the twelve (12) months ending with the current month; or (2) the minimum kW specified in an agreement for service, whichever is the greater.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

RATE SCHEDULE E-32 S
SMALL GENERAL SERVICE (21 kW – 100 kW)

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313..

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. xxxxx.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 20 and less than or equal to 100 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

APS

RATE SCHEDULE E-32 S
SMALL GENERAL SERVICE (21 kW – 100 kW)

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32 M
MEDIUM GENERAL SERVICE (101 kW - 400 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 100 kW and less than or equal to 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 1.068	per day, or
For service through Instrument-Rated Meters:	$ 1.627	per day, or
For service at Primary Voltage:	$ 3.419	per day, or
For service at Transmission Voltage:	$ 22.915	per day

RATE SCHEDULE E-32 M
MEDIUM GENERAL SERVICE (101 kW - 400 kW)

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 8.406	per kW for the first 100 kW, plus
	$ 4.240	per kW for all additional kW, or
Primary Service:	$ 7.574	per kW for the first 100 kW, plus
	$ 3.408	per kW for all additional kW, or
Transmission Service:	$ 2.806	per kW for the first 100 kW, plus
	$ 0.130	per kW for all additional kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10419 per kWh for the first 200 kWh per kW, plus $0.06134 per kWh for all additional kWh	$0.08719 per kWh for the first 200 kWh per kW, plus $0.04434 per kWh for all additional kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.601	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.345	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary:	$ 2.696	per day, or
Transmission:	$ 22.192	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 Kv). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00188	per kWh

RATE SCHEDULE E-32 M
MEDIUM GENERAL SERVICE (101 kW - 400 kW)

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

Secondary Service:	$ 8.406	per kW for the first 100 kW, plus
	$ 4.240	per kW for all additional kW, plus
	$ 0.00133	per kWh, or
Primary Service:	$ 7.574	per kW for the first 100 kW, plus
	$ 3.408	per kW for all additional kW, plus
	$ 0.00133	per kWh, or
Transmission Service:	$ 2.806	per kW for the first 100 kW, plus
	$ 0.130	per kW for all additional kW, plus
	$ 0.00133	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10098 per kWh for the first 200 kWh per kW, plus $0.05813 per kWh for all additional kWh	$0.08398 per kWh for the first 200 kWh per kW, plus $0.04113 per kWh for all additional kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

MINIMUM

The bill for Standard Offer and Direct Access customers will not be less than the applicable Bundled Standard Offer Service Basic Service charge plus $2.330 for each kW of either: (1) the highest kW established during the twelve (12) months ending with the current month; or (2) the minimum kW specified in an agreement for service, whichever is the greater.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment. Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load.

APS

RATE SCHEDULE E-32 M
MEDIUM GENERAL SERVICE (101 kW - 400 kW)

POWER FACTOR (cont)

Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. xxxxx.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

APS

RATE SCHEDULE E-32 M
MEDIUM GENERAL SERVICE (101 kW - 400 kW)

CONTRACT PERIOD

For customers with monthly maximum demands greater than 100 and less than or equal to 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 1.068	per day, or
For service through Instrument-Rated Meters:	$ 1.627	per day, or
For service at Primary Voltage:	$ 3.419	per day, or
For service at Transmission Voltage:	$ 22.915	per day

APS

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 8.710	per kW for the first 100 kW, plus
	$ 4.386	per kW for all additional kW, or
Primary Service:	$ 8.132	per kW for the first 100 kW, plus
	$ 3.808	per kW for all additional kW, or
Transmission Service:	$ 3.110	per kW for the first 100 kW, plus
	$ 0.276	per kW for all additional kW.

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10117 per kWh for the first 200 kWh per kW, plus $0.06113 per kWh for all additional kWh	$0.08528 per kWh for the first 200 kWh per kW, plus $0.04524 per kWh for all additional kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.601	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.345	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary:	$ 2.696	per day, or
Transmission:	$ 22.192	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00188	per kWh

APS

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

Secondary Service:	$ 8.710	per kW for the first 100 kW, plus
	$ 4.386	per kW for all additional kW, plus
	$ 0.00492	per kWh, or
Primary Service:	$ 8.132	per kW for the first 100 kW, plus
	$ 3.808	per kW for all additional kW, plus
	$ 0.00492	per kWh, or
Transmission Service:	$ 3.110	per kW for the first 100 kW, plus
	$ 0.276	per kW for all additional kW, plus
	$ 0.00492	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.09437 per kWh for the first 200 kWh per kW, plus $0.05433 per kWh for all additional kWh	$0.07848 per kWh for the first 200 kWh per kW, plus $0.03844 per kWh for all additional kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

MINIMUM

The bill for Standard Offer and Direct Access customers will not be less than the applicable Bundled Standard Offer Service Basic Service charge plus $2.414 for each kW of either: (1) the highest kW established during the twelve (12) months ending with the current month; or (2) the minimum kW specified in an agreement for service, whichever is the greater.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

APS

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

POWER FACTOR (cont)

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. xxxxx.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

APS

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

CONTRACT PERIOD

For customers with monthly maximum demands greater than 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32TOU XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 20 kW and less than or equal to 100 kW per month.

The Company will initially place the Customer on the applicable Rate Schedule E-32TOU XS, E-32TOU S, E-32 TOU M, or E-32TOU L based on the Average Monthly Maximum Demand, as determined by the Company.

The Customer will be billed on Schedule E-32TOU S or E-32TOU XS depending on the On-peak Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Basic Service Charge:

For service through Self-Contained Meters	$ 0.624	per day, or
For service through Instrument-Rated Meters:	$ 1.150	per day, or
For service at Primary Voltage:	$ 2.942	per day

RATE SCHEDULE E-32TOU XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)
TIME OF USE

RATES (cont)

Bundled Standard Offer Service

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
For Secondary Service: $ 0.17149 per kWh for the first 5,000 On-Peak kWh, plus $ 0.08217 per kWh for all additional On-Peak kWh, plus $ 0.12555 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.04189 per kWh for all additional Off-Peak kWh, or	For Secondary Service: $ 0.15326 per kWh for the first 5,000 On-Peak kWh, plus $ 0.06389 per kWh for all additional On-Peak kWh, plus $ 0.10732 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.02858 per kWh for all additional Off-Peak kWh, or
For Primary Service: $ 0.16939 per kWh for the first 5,000 On-Peak kWh, plus $ 0.08007 per kWh for all additional On-Peak kWh, plus $ 0.12345 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.03979 per kWh for all additional Off-Peak kWh	For Primary Service: $ 0.15116 per kWh for the first 5,000 On-Peak kWh, plus $ 0.06179 per kWh for all additional On-Peak kWh, plus $ 0.10522 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.02648 per kWh for all additional Off-Peak kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.124	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.378	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary:	$ 2.696	per day

These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00188	per kWh

RATE SCHEDULE E-32TOU XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)
TIME OF USE

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
For Secondary Service: $ 0.05324 per kWh for the first 5,000 On-Peak kWh, plus $ 0.01383 per kWh for all additional On-Peak kWh, plus $ 0.04386 per kWh for the first 5,000 Off-Peak kWh plus $ 0.01011 per kWh for all additional Off-Peak kWh, or	For Secondary Service: $ 0.05315 per kWh for the first 5,000 On-Peak kWh, plus $ 0.01371 per kWh for all additional On-Peak kWh, plus $ 0.04378 per kWh for the first 5,000 Off-Peak kWh plus $ 0.01003 per kWh for all additional Off-Peak kWh, or
For Primary Service: $ 0.05114 per kWh for the first 5,000 On-Peak kWh, plus $ 0.01173 per kWh for all additional On-Peak kWh, plus $ 0.04176 per kWh for the first 5,000 Off-Peak kWh plus $ 0.00801 per kWh for all additional Off-Peak kWh	For Primary Service: $ 0.05105 per kWh for the first 5,000 On-Peak kWh, plus $ 0.01161 per kWh for all additional On-Peak kWh, plus $ 0.04168 per kWh for the first 5,000 Off-Peak kWh plus $ 0.00793 per kWh for all additional Off-Peak kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.11637 per kWh for the first 5,000 On-Peak kWh, plus $ 0.06646 per kWh for all additional On-Peak kWh, plus $ 0.07981 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.02990 per kWh for all additional Off-Peak kWh	$ 0.09823 per kWh for the first 5,000 On-Peak kWh, plus $ 0.04830 per kWh for all additional On-Peak kWh, plus $ 0.06166 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.01667 per kWh for all additional Off-Peak kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

MINIMUM

The bill for Standard Offer and Direct Access customers will not be less than the applicable Bundled Standard Offer Service Basic Service Charge.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading

RATE SCHEDULE E-32TOU XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)
TIME OF USE

POWER FACTOR (cont)

unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the billing period, as determined from readings of the Company's meter.

Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during either the On-Peak or Off-Peak hours of the billing period, as determined from readings of the Company's meter.

On-peak Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during the On-peak hours of the billing period, as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the On-peak Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the On-peak Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum On-peak kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

RATE SCHEDULE E-32TOU XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)
TIME OF USE

ADJUSTMENTS (cont)

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. xxxxx.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands less than 20 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32TOU S
SMALL GENERAL SERVICE (21 kW - 100 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 20 kW and less than or equal to 100 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32TOU XS, E-32TOU S, E-32TOU M, or E-32TOU L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination.

Customers will be billed on Schedule E-32 S or E-32 XS depending on the On-peak Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Basic Service Charge:

For service through Self-Contained Meters:	$ 1.101	per day, or
For service through Instrument-Rated Meters:	$ 1.627	per day, or
For service at Primary Voltage:	$ 3.419	per day

RATE SCHEDULE E-32TOU S
SMALL GENERAL SERVICE (21 kW - 100 kW)
TIME OF USE

RATES (cont)

Bundled Standard Offer Service

Demand Charge:

Secondary Service:	$ 12.596	per kW for the first 100 On-Peak kW, plus
	$ 7.729	per kW for all additional On-Peak kW, plus
	$ 5.429	per kW for the first 100 Off-Peak kW, plus
	$ 3.016	per kW for all additional Off-Peak kW
Primary Service:	$ 11.096	per kW for the first 100 On-Peak kW, plus
	$ 6.979	per kW for all additional On-Peak kW, plus
	$ 4.729	per kW for the first 100 Off-Peak kW, plus
	$ 2.616	per kW for all additional Off-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.07528 per kWh during On-Peak hours, plus $ 0.05973 during Off-Peak hours	$ 0.05757 per kWh during On-Peak hours, plus $ 0.04202 during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.601	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.378	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary:	$ 2.696	per day

These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00188	per kWh

RATE SCHEDULE E-32TOU S
SMALL GENERAL SERVICE (21 kW - 100 kW)
TIME OF USE

Unbundled Standard Offer Service (cont)

Delivery Charge:

Secondary Service:	$ 7.720	per kW for the first 100 On-Peak kW, plus
	$ 2.853	per kW for all additional On-Peak kW, plus
	$ 3.573	per kW for the first 100 Off-Peak kW, plus
	$ 1.160	per kW for all additional Off-Peak kW, plus
Primary Service:	$ 6.220	per kW for the first 100 On-Peak kW, plus
	$ 2.103	per kW for all additional On-Peak kW, plus
	$ 2.873	per kW for the first 100 Off-Peak kW, plus
	$ 0.760	per kW for all additional Off-Peak kW, plus

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 4.876 per On-Peak kW, plus $ 1.856 per Off-Peak kW, plus $ 0.07340 per kWh during On-Peak hours, plus $ 0.05785 per kWh during Off-Peak hours	$ 4.876 per On-Peak kW, plus $ 1.856 per Off-Peak kW, plus $ 0.05569 per kWh during On-Peak hours, plus $ 0.04014 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

MINIMUM

The bill for Standard Offer and Direct Access customers will not be less than the applicable Bundled Standard Offer Service Basic Service Charge plus $ 2.150 for each of either: (1) the highest On-Peak kW established during the twelve (12) months ending with the current month; or (2) the minimum kW specified in an agreement for service, whichever is the greater.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

RATE SCHEDULE E-32TOU S
SMALL GENERAL SERVICE (21 kW - 100 kW)
TIME OF USE

POWER FACTOR (cont)

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the billing period, as determined from readings of the Company's meter.

Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during either the On-Peak or Off-Peak hours of the billing period, as determined from readings of the Company's meter.

On-peak Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during the On-peak hours of the billing period, as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the On-peak Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the On-peak Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum On-peak kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

RATE SCHEDULE E-32TOU S
SMALL GENERAL SERVICE (21 kW - 100 kW)
TIME OF USE

ADJUSTMENTS (cont)

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. xxxxx.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 20 and less than 100 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32TOU M
MEDIUM GENERAL SERVICE (101 kW – 400 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 100 kW and less than or equal to 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32TOU XS, E-32TOU S, E-32TOU M, or E-32TOU L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-35 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage; primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 1.101	per day, or
For service through Instrument-Rated Meters:	$ 1.627	per day, or
For service at Primary Voltage:	$ 3.419	per day, or
For service at Transmission Voltage:	$ 22.915	per day

RATE SCHEDULE E-32TOU M
MEDIUM GENERAL SERVICE (101 kW – 400 kW)
TIME OF USE

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 13.258	per kW for the first 100 On-Peak kW, plus
	$ 7.844	per kW for all additional On-Peak kW, plus
	$ 5.713	per kW for the first 100 Off-Peak kW, plus
	$ 2.995	per kW for all additional Off-Peak kW
Primary Service:	$ 11.758	per kW for the first 100 On-Peak kW, plus
	$ 7.094	per kW for all additional On-Peak kW, plus
	$ 5.013	per kW for the first 100 Off-Peak kW, plus
	$ 2.595	per kW for all additional Off-Peak kW
Transmission Service:	$ 6.258	per kW for the first 100 On-Peak kW, plus
	$ 4.724	per kW for all additional On-Peak kW, plus
	$ 3.513	per kW for the first 100 Off-Peak kW, plus
	$ 1.795	per kW for all additional Off-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.07687 per kWh during On-Peak hours, plus $ 0.06099 during Off-Peak hours	$ 0.05878 per kWh during On-Peak hours, plus $ 0.04289 during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.601	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.378	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary:	$ 2.696	per day, or
Transmission:	$ 22.192	per day

These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

RATE SCHEDULE E-32TOU M
MEDIUM GENERAL SERVICE (101 kW – 400 kW)
TIME OF USE

RATES (cont)

Unbundled Standard Offer Service (cont)

Revenue Cycle Service Charges (cont)

Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00188	per kWh

Delivery Charge:

Secondary Service:	$ 10.549	per kW for the first 100 On-Peak kW, plus
	$ 5.135	per kW for all additional On-Peak kW, plus
	$ 4.682	per kW for the first 100 Off-Peak kW, plus
	$ 1.964	per kW for all additional Off-Peak kW
Primary Service:	$ 9.049	per kW for the first 100 On-Peak kW, plus
	$ 4.385	per kW for all additional On-Peak kW, plus
	$ 3.982	per kW for the first 100 Off-Peak kW, plus
	$ 1.564	per kW for all additional Off-Peak kW
Transmission Service:	$ 3.549	per kW for the first 100 On-Peak kW, plus
	$ 2.015	per kW for all additional On-Peak kW, plus
	$ 2.482	per kW for the first 100 Off-Peak kW, plus
	$ 0.764	per kW for all additional Off-Peak kW

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 2.709 per On-Peak kW, plus $ 1.031 per Off-Peak kW, plus $ 0.07499 per kWh during On-Peak hours, plus $ 0.05911 per kWh during Off-Peak hours	$ 2.709 per On-Peak kW, plus $ 1.031 per Off-Peak kW, plus $ 0.05690 per kWh during On-Peak hours, plus $ 0.04101 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

RATE SCHEDULE E-32TOU M
MEDIUM GENERAL SERVICE (101 kW – 400 kW)
TIME OF USE

MINIMUM

The bill for Standard Offer and Direct Access customers will not be less than the applicable Bundled Standard Offer Service Basic Service Charge plus $ 2.138 for each of either: (1) the highest On-Peak kW established during the twelve (12) months ending with the current month; or (2) the minimum kW specified in an agreement for service, whichever is the greater.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the billing period, as determined from readings of the Company's meter.

Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during either the On-Peak or Off-Peak hours of the billing period, as determined from readings of the Company's meter.

On-peak Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during the On-peak hours of the billing period, as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the On-peak Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the On-peak Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum On-peak kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

RATE SCHEDULE E-32TOU M
MEDIUM GENERAL SERVICE (101 kW – 400 kW)
TIME OF USE

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. xxxxx.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 100 and less than 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32TOU XS, E-32TOU S, E-32TOU M, or E-32TOU L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This rate schedule is applicable to all Standard Offer and Direct Access electric service required when such service is supplied at one point of delivery and measured through one meter. Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-35 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage; primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 1.101	per day, or
For service through Instrument-Rated Meters:	$ 1.627	per day, or
For service at Primary Voltage:	$ 3.419	per day, or
For service at Transmission Voltage:	$ 22.915	per day

RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 13.620	per kW for the first 100 On-Peak kW, plus
	$ 8.103	per kW for all additional On-Peak kW, plus
	$ 5.572	per kW for the first 100 Off-Peak kW, plus
	$ 3.045	per kW for all additional Off-Peak kW
Primary Service:	$ 12.120	per kW for the first 100 On-Peak kW, plus
	$ 7.353	per kW for all additional On-Peak kW, plus
	$ 4.872	per kW for the first 100 Off-Peak kW, plus
	$ 2.645	per kW for all additional Off-Peak kW
Transmission Service:	$ 6.620	per kW for the first 100 On-Peak kW, plus
	$ 4.983	per kW for all additional On-Peak kW, plus
	$ 3.372	per kW for the first 100 Off-Peak kW, plus
	$ 1.845	per kW for all additional Off-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.07672 per kWh during On-Peak hours, plus $ 0.06086 during Off-Peak hours	$ 0.05866 per kWh during On-Peak hours, plus $ 0.04281 during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.601	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.378	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary:	$ 2.696	per day, or
Transmission:	$ 22.192	per day

These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

RATES (cont)

Unbundled Standard Offer Service (cont)

Revenue Cycle Service Charges (cont)

Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00188	per kWh

Delivery Charge:

Secondary Service:	$ 10.309	per kW for the first 100 On-Peak kW, plus
	$ 4.792	per kW for all additional On-Peak kW, plus
	$ 4.312	per kW for the first 100 Off-Peak kW, plus
	$ 1.785	per kW for all additional Off-Peak kW
Primary Service:	$ 8.809	per kW for the first 100 On-Peak kW, plus
	$ 4.042	per kW for all additional On-Peak kW, plus
	$ 3.612	per kW for the first 100 Off-Peak kW, plus
	$ 1.385	per kW for all additional Off-Peak kW
Transmission Service:	$ 3.309	per kW for the first 100 On-Peak kW, plus
	$ 1.672	per kW for all additional On-Peak kW, plus
	$ 2.112	per kW for the first 100 Off-Peak kW, plus
	$ 0.585	per kW for all additional Off-Peak kW

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 3.311 per On-Peak kW, plus $ 1.260 per Off-Peak kW, plus $ 0.07484 per kWh during On-Peak hours, plus $ 0.05898 per kWh during Off-Peak hours	$ 3.311 per On-Peak kW, plus $ 1.260 per Off-Peak kW, plus $ 0.05678 per kWh during On-Peak hours, plus $ 0.04093 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

MINIMUM

The bill for Standard Offer and Direct Access customers will not be less than the applicable Bundled Standard Offer Service Basic Service Charge plus $ 2.132 for each of either: (1) the highest On-Peak kW established during the twelve (12) months ending with the current month; or (2) the minimum kW specified in an agreement for service, whichever is the greater.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the billing period, as determined from readings of the Company's meter.

Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during either the On-Peak or Off-Peak hours of the billing period, as determined from readings of the Company's meter.

On-peak Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during the On-peak hours of the billing period, as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the On-peak Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the On-peak Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum On-peak kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. xxxxx.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE SOLAR-3
CLASSIFIED SERVICE
SOLAR POWER PILOT PROGRAM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. The Solar Power Pilot Program is offered as a three-year pilot program and is available to residential standard offer customers who wish to purchase electricity generated from solar sources for their homes. The Company will procure or construct new solar generation resources to provide service under Schedule Solar-3. The Company shall limit participation in Schedule Solar-3 based on the amount of solar generation resources available.

APPLICATION

Service under this schedule provides all or a portion of the customer's service from solar electric generating systems producing AC electricity and delivered via APS' electric power grid. All provisions of the Customer's current applicable rate schedule will apply, including the unbundled generation components as applied to the Customers total monthly energy consumption. However, the charges in adjustment Schedule EIS and Adjustment Schedule ~~EPS-1~~RES will not apply to the Solar Power Energy (kWh) served in accordance with Schedule Solar-3, up to 100% of the customer's total monthly kWh supplied by the Company. The customer is required to subscribe for a minimum term of one year. Direct Access customers are not eligible for service under this rate schedule.

SERVICE CHARGES

The customer shall be charged a Solar Power Premium Rate for all Solar Power Energy (kWh) served under this rate schedule. The Solar Power Premium Rate shall be the Solar Power Price, which represents the Company's price for Solar Power used to serve this rate schedule credited for the Avoided Cost, which represents the Company's associated savings in generation costs. The Solar Power Premium Rate shall be applied to the Solar Power Energy on a monthly basis.

Solar Power Price:	$0.225 per kWh
Avoided Cost Credit:	$0.059 per kWh
Solar Power Premium Rate:	$0.166 per kWh

Solar Power Energy shall be a percentage of the customer's total monthly energy (kWh) supplied by the Company. ~~Two~~ Four options are available:

A. Solar Power shall account for 100.0% of the customer's total monthly energy supplied by the Company.
B. Solar Power shall account for 50.0% of the customer's total monthly energy supplied by the Company.
C. Solar Power shall account for 35.0% of the customer's total monthly energy supplied by the Company.
D. Solar Power shall account for 10.0% of the customer's total monthly energy supplied by the Company.

TERMS AND CONDITIONS

Subject to Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contain provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR STANDARD OFFER AND DIRECT ACCESS SERVICES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and/or sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

2.2 Service Establishment and Customer Request for Special Service Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month

2.2.1 The customer will additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to the point of delivery.

2.2.2 The customer will additionally be required to pay an after-hours charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established after 5:00 p.m. on a day other than the day of request.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

2.2.3 The customer will additionally be required to pay a same day connect charge of $75.00 if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established on the same business day the request is being made, and Company agrees to work the request on the same business day of the request. This will be charged regardless of the time the order may be worked by Company on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

2.2.4 The customer will additionally be required to pay $75.00 per crew person per hour when customer requests services that do not meet the definition of service establishment as defined in A.A.C. R14-2-203.D.3 (such as metering equipment installations which include instrument transformers but excluding the cost of meters, maintenance or planned outages, etc.) that require the availability of Company employees after hours, on a weekend day, or on a Company holiday. The number of employees utilized by Company in fulfilling such requests shall be at the sole discretion of Company. Customers will be given notice of estimated charges prior to the work being performed.

Company holidays are New Year's Day, Martin Luther King, Jr. Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, The Day After Thanksgiving, and Christmas Day.

2.2.5 Company may waive the service establishment charge where:

2.2.5.1 No field trip is required because applicant accepts responsibility for energy billed and not yet paid and the change is effective with the last meter read and meter read date billed.

2.2.5.2 Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company. This service agreement is for property owners that have established credit with Company and provides for continuous service to the landlord between tenants.

2.2.5.3 Where multiple connects are performed during the same site visit, in the same applicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two delivery points.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.5 or 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill from the same or a prior service address.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill from the same or a prior service address.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 ~~Residential~~ Establishment of Credit or Security Deposit

2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new applicant for service at a primary and/or secondary residence if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 The applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received within six (6) months of the current date which states that the applicant had a timely payment history for the prior twelve (12) consecutive months at the time of service discontinuation.

2.5.1.4 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.1.5 Where three or more additional residential services are requested, Company may require customer to establish or reestablish a security deposit.

2.5.2 Residential Establishment of Credit or Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Non-residential Establishment of Security Deposit – All non-residential applicants will be required to place a cash deposit to secure payment of bills for service as prescribed herein, unless:

2.5.3.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.3.2 The applicant provides a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Establishment or Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Non-residential - Company may require a non-residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits – Once it is determined that a security deposit is required, the following will apply:

2.7.1 Security deposits may be required for each service location.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

2.7.2 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by Company in accordance with this section:

2.7.2.1 If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.2.2 If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that Company is providing bundled electric service.

2.7.2.3 If the customer's average consumption increases: by more than ten (10) percent for residential accounts or five (5) percent for nonresidential accounts within a twelve (12) consecutive month period and credit has not been established, an additional security deposit may, at Company's option, be required.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest from the date the deposit was collected at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed the higher amount of either one (1) time the customer's maximum monthly bill or two (2) times the customer's average monthly bill as estimated by Company for the services being provided by Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be ~~returned or~~ credited or returned to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless customer has filed bankruptcy in the last 12 months.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is receiving bundled service, Company will use reasonable care in initially establishing service to the customer under the most advantageous rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 Optional Rates – Certain optional rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. Billing under the alternate rate will become effective from the next regularly scheduled meter reading, -after the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access service will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

3.5 Any customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access service for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer service.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, at customer's request, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than fifteen (15) calendar days from the billing date. Any payment not received within this time frame will be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved charges. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company ~~will~~may correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Schedule 8 (Bill Estimation) shall be applied when Company cannot obtain a complete and valid meter read. Situations that result in an estimated meter read include inclement weather, lack of access to a customer's meter, energy diversion, labor unavailability and equipment malfunction.

4.3.2.1 Refunds or credits to customers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion.

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of meter tampering or energy diversions, corrected charges for underbillings shall go back to the date meter tampering or energy diversions began, as determined by Company.

4.3.2.3.4 Where lack of access to the meter (caused by the customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the billing month of the last Company obtained meter read date.

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

4.3.3 Where Company is responsible for rendering the customer's bill, Company will provide a monthly incentive of $0.48 per customer to customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified or cashier's check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer will be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Termination Process Charges

4.5.1 Company will require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.2 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.3 To avoid termination of service, the customer will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

4.6 On-site Evaluation – Company will require payment of an On-site Evaluation Charge of $82.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of whether the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service to the designated point of delivery, as specified in Section 6.3 of this Schedule, at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service, except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites -

5.4.1 Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to Company's equipment located on customer's sites for the purpose of repair, maintenance, and service restoration work that Company may need to perform.

5.4.2 Company's authorized agents shall have satisfactory unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, to verify that customer is in compliance with its obligations, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to ~~deal~~ work with the customer, Company in its opinion does not have satisfactory unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any rate options where, in Company's opinion, access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter ~~as a one-time charge~~ is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter plus the cost incurred to install the specialized meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this ~~schedule~~section.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of an extension to serve a customer, which is either on sites owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way granted to, or obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense. Company will notify the customer in writing of the violations.

5.6 Load Characteristics – The customer shall exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. Customer shall meet power factor requirements as specified on applicable rate schedules.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery except for Company's meters and special equipment. The customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company. In circumstances where a clearance is not required by law, Company may require customer to execute a Letter In-Lieu of Electrical Clearance.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.asp.

6.1.2 Where a customer requests, and Company approves ~~of~~, a special meter reading device or communications services or devices to accommodate the customer's needs, the cost for such additional equipment and usage fees shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will result in charge to the MSP of the replacement costs, plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of Company's Schedule 10;

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. If Company must temporarily replace the MSP's meter and/or associated metering equipment during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter.

6.3.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.

6.3.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors.

6.3.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and customer shall mutually agree upon the designated point of delivery.

6.3.4 For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry Company issued identification which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company (or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule 10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's bill estimation procedures approved by the Arizona Corporation Commission. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the MRSP, the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer, person or entity demonstrated to have tampered with the meter and/or benefited from the tampering or

diverson will be billed for the estimated energy and, if applicable, demand, for the period in which the energy diversion took place. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer, person or entity demonstrated to have tampered with the meter and/or diverted energy will also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.3.1 Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and demand that would have registered had the meter been operating properly.

6.4.4 Where Company is the MRSP, Company will, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $16.50 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $50.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments (developments consisting of apartments, condominiums or townhouse developments built with four or more floors, usually using elevators for accessing floors) – Company will allow master metering for residential units where the residential units are privately owned, provided the building will be served by a

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 Company observes, or has evidence of, ~~The existence of an obvious~~a hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.2.5 Customer made payments to avoid/stop non-payment disconnection with a dishonored payment. Prior to reconnection of service, repayment of those funds and all other delinquent amounts will be required in cash, money order, or certified funds.

7.2.6 Customer paid to reconnect service with a dishonored payment. Prior to reconnection of service, payment of those funds and all other delinquent amounts will be required in cash, money order or certified funds.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. ~~If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.~~

~~For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.~~

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

SERVICE SCHEDULE 4: TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through ~~7~~ 8 are all satisfied.

1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1); and

2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and

3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

4. For Standard Offer customers, totalized metering may be accomplished by providing electronically totalized demand and energy reads or by means of a physical wire interconnection of metering information with the customer providing conduit between the SESs; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and

5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and

6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and

7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

8. Customers electing to have accounts either Adjacent or Remote Totalized metered will be required to maintain the accounts in the approved totalized configuration for a minimum of one (1) year.

B. Adjacent Totalized Metering will apply when conditions A.1-A.~~7~~ 8 and the following conditions are met:

SERVICE SCHEDULE 4: TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

1. The customer's total load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

2. Company requires that load be split and served from multiple SESs; and

3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.8~~7~~ are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

SERVICE SCHEDULE 4: TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

4. In the event the customer should elect to remove a meter from a totalized metering configuration, the customer will continue to be responsible for the minimum billing kW parameters noted on the Customer's Electric Supply Agreement.

5. Customer may elect an alternate rate schedule for accounts that are removed from the totalized configuration however no further rate schedule changes may be made within the succeeding twelve (12) month period in accordance with the provisions of the Company's Schedule 1.

SERVICE SCHEDULE 5
GUIDELINES FOR ELECTRIC CURTAILMENT

1. Arizona Public Service Company (Company) shall have no liability of obligation for claims arising out of the procedures for curtailment or interruption of electric service effected by it in accordance with such guidelines or such supplemental, amendatory or implementary guidelines or regulations as may hereafter be established and as provided by law.

2. Company shall endeavor to identify any electric customer(s) who might be classified as having either essential or critical loads. In the event that any customer of Company is dissatisfied by the classification of Customer by Company, or with the amount of such customer's load (if any) classified by the Company as critical or essential, the Customer may bring the matter to either the Company or the Commission and request a determination in regard thereto. However, until such redetermination is made by the Commission or the Company, customer's original classification for purposes of electric curtailment under this Schedule shall be unaffected.

3. Company shall endeavor to, as circumstances permit and as further discussed in the Company's detailed Electric Load and Curtailment Plan, to notify County emergency personnel, or similar local authorities, of existing or developing situations involving the curtailment or interruption of APS customers pursuant to this Schedule #5.

4. DEFINITIONS

   4.1 Essential Loads – Loads necessary to serve facilities used to protect the health and safety of the public, such as: hospitals, 911 Centers, national defense installations, sewage facilities and domestic water facilities. Loads necessary to serve 911 Centers, police stations, and fire stations, which do not have independent back-up generation and require APS' electric service for operation of essential emergency equipment.

   4.2 Critical Loads – That portion of the electric load of nonresidential customers, which in the event of 100 percent curtailment of service, would cause excessive damage to equipment or material being processed, or where such interruption would create grave hazards to employees or the public.

   4.3 Major Use Customers/Others (With Notice) – Those customers having relatively large loads (over 1000 kW) or a substantial number of employees or other special circumstances that make it appropriate to schedule blackouts or curtailments different from typical customers. Customers who qualify as Major Use/Others (With Notice) can take 100 percent curtailment when sufficient notice is provided. These loads will be interrupted after the required notification period. "Sufficient", "required", and "appropriate" notice is that notice that APS, after consultation with the affected customer, has determined will allow the customer to curtail in a safe and efficient manner. Such notice necessarily varies from customer to customer.

   4.4 Others (With or Without Notice) – All customers not meeting the above definitions. These customers will be interrupted (with or without notice) if voluntary curtailment measures are not sufficient to alleviate the situation.

5. GUIDELINES TO BE APPLICABLE IN EVENT OF INTERRUPTION OR CURTAILMENT OF ELECTRIC SERVICE BY COMPANY TO ITS CUSTOMERS DUE TO POWER SUPPLY INTERRUPTIONS, FUEL SHORTAGE OR TRANSMISSION EMERGENCY PURSUANT TO CORPORATION COMMISSION RULE R14-2-208, PROVISION OF SERVICE, PARAGRAPH E.

   5.1 Operating Procedures Prior to Customer Load Curtailment

SERVICE SCHEDULE 5
GUIDELINES FOR ELECTRIC CURTAILMENT

5.1.1 The following items shall be pursued concurrently

5.1.1.1 Reschedule maintenance of transmission components and generating units, where practical.

5.1.1.2 Utilize spinning reserve.

5.1.1.3 Discontinue all non-firm wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.4 Do not enter into any new wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.5 Start all standby units.

5.1.1.6 Contact other utilities and/or agencies for emergency assistance.

5.1.1.7 Invoke emergency and short-term contractual schedules with other utilities and/or agencies.

5.1.1.8 Reduce system voltage, where practical.

5.1.1.9 Reduce non-essential Company uses such as flood lighting, sign lighting, display lighting, office lighting, electric cooling and heating, etc., where practical.

5.1.1.10 Provide information through the media or other appropriate medians to the public which will contain instructions on how customers can assist Company in case of an emergency power outage.

5.1.1.11 Work with government agencies and environmental groups to seek waivers on environmental constraints and/or expedite permitting process for company-owned generation, as well as, customer generation, as appropriate.

5.2 Voluntary Customer Load Curtailment

5.2.1 Public Appeal

5.2.1.1 An advisory message procedure will be used when Company has advance indications that it will not be able to meet future peak loads. These messages will request voluntary load reduction during specific hours on specific days.

5.2.1.2 An emergency bulletin procedure will be used for instant notification to the public in the event there is no advance indication of a power shortage. These bulletins will request the immediate voluntary cooperation of all customers in reducing electric loads.

5.2.1.2.1 These bulletins will request all customers to reduce the use of all electrically operated equipment and devices, where possible.

SERVICE SCHEDULE 5
GUIDELINES FOR ELECTRIC CURTAILMENT

5.2.1.2.2 Company will have a prepared statement to read which will give current information on the Power Supply Interruption, Fuels Shortage or Transmission Emergency.

5.3 Contractually Interruptible Load

5.3.1 Company shall invoke contractual interruption provisions to the extent appropriate.

5.3.2 Company shall interrupt non-firm wholesale customer(s) as appropriate.

5.4 Involuntary Customer Load Curtailment

5.4.1 If the load reduction realized from application of the voluntary curtailment procedures is not sufficient to alleviate the power shortage, Company will reduce voltage if and to the extent practical and in accordance with normal applicable electric utility operation standards.

5.4.2 If further load reduction is required, load will be reduced as follows:

5.4.2.1 Circuits not classified with "Major Use/Others With Notice, Critical or Essential" customers will be interrupted on a rotating basis. The frequency and duration of such interruptions will be dependent upon the magnitude and nature of the power shortage. The frequency and duration of such interruptions shall also consider the circumstances of Major Use Customers.

5.4.2.2 Accurate records will be kept to ensure that these circuits are rotated in an equitable and technically feasible manner.

5.4.2.3 Circuits classified as "Major Use/Others" will be interrupted upon the giving of appropriate notice.

5.4.2.4 Customers on circuits which serve critical loads will be required to curtail the non-critical portion of their loads. Thereafter, circuits which serve critical loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as critical may be curtailed if they possess back-up generation sufficient to meet their entire load requirement. If a customer having a critical load refuses or fails to curtail his electric consumption down to the critical load, he shall thereupon not be considered to have a critical load for purposes of this Schedule.

5.4.2.5 Circuits which serve essential loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as essential may be curtailed if they possess back-up generation sufficient to meet their entire load requirement.

5.5 Sudden Shortages of Power

In the event that time does not allow for the implementation of the Electric Curtailment Guidelines, Company may resort to its emergency operations procedures, with or without notice.

SERVICE SCHEDULE 5
GUIDELINES FOR ELECTRIC CURTAILMENT

5.6 Automatic Load Shedding

In the event that there is a major electrical disturbance threatening the interconnected Southwest system with blackout conditions, emergency devices such as under frequency load shedding, transfer tripping, etc., will be utilized to maintain the optimum system stability.

6. ELECTRIC CURTAILMENT OF FIRM WHOLESALE CUSTOMERS

6.1 The term "firm wholesale customer" shall be defined as those APS customers who purchase, on a firm basis, electricity from the Company for purposes of resale.

6.2 In any given instance where a curtailment of wholesale power deliveries is involved, and subject to any required approvals of the Federal Energy Regulatory Commission or contractual provisions to the contrary, Company shall notify its firm wholesale customers, requesting that they curtail electric service to their retail customers during the period that Company's system is affected by power shortages. In the event that Company is unable to obtain the cooperation of a firm wholesale customer, it may seek an order from appropriate governmental authority requiring the firm wholesale customer to accept a reduction of electricity deliveries proportionate to the curtailment being effected on Company's system.

7. ELECTRIC LOAD AND CURTAILMENT PLAN

A detailed electric load and curtailment plan shall be kept on file with the Arizona Corporation Commission. This plan shall contain specific procedures for implementation of the above, along with the name(s) and telephone number(s) of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. This plan shall be updated at least annually, and it or amendments thereto shall become effective upon submission to the Arizona Corporation Commission.

7.1 Company shall contact the Director, Utilities Division, or their designee, as soon as practical for any curtailment pursuant to this Schedule #5.

SERVICE SCHEDULE 8
BILL ESTIMATION

Arizona Public Service Company (APS or Company) regularly encounters situations in which APS cannot obtain a complete and valid meter read. Situations that result in an estimated meter read include inclement weather, lack of access to a customer's meter, energy diversion, labor unavailability and equipment malfunction. Without a valid meter read, the customer's energy usage and/or demand must be estimated in order to render a bill for the missing read period. A bill based on estimated usage is often referred to as an "estimated bill."

APS uses situation specific methods to estimate electrical usage to ensure that the most accurate usage estimate is obtained. This Schedule describes the estimation methods and procedures used when an actual meter read cannot be obtained or when energy diversion and/or meter tampering has occurred. The estimating process is applicable to customers receiving Standard Offer service and to direct access customers receiving unbundled delivery service from the Company.

1. GENERAL

1.1 Estimating a read for energy (kWh) and/or demand (kW) is performed in accordance with the provisions of this Schedule or such supplemental or amendatory guidelines or regulations as may hereafter be established and as provided by law.

1.2 This Schedule shall be considered a part of all rate schedules.

1.3 Upon discovery of the need to estimate kWh or kW, Company will make reasonable attempt (s) to secure an accurate meter reading and to resolve no-access issues.

1.4 Company is not obligated to obtain, or attempt to obtain, a customer supplied meter read prior to sending an estimated bill. In circumstances where APS has agreed in writing to permit customer supplied meter reads in accordance with Arizona Corporation Commission (ACC or Commission) regulations and that customer fails to provide Company with the meter read, estimation is also allowed.

1.5 Estimates due to equipment malfunctions may exceed one month if the malfunction of Company owned or maintained equipment could not be reasonably discovered and/or corrected before the need for additional estimates, or if the equipment malfunction is with regard to customer-owned or maintained equipment.

1.6 This schedule is not intended to supersede the Commission's rules and regulations in effect at the time the Commission approved this Schedule 8 without a specific decision of the Commission.

2. BILL ESTIMATION

2.1 The causes that result in an estimated bill include but are not limited to:

2.1.1 Inclement weather where conditions prevent meter access or compromise APS employee safety as determined by Company.

2.1.2 Lack of access to the meter either due to conditions on the customer's premise or to road closures that prevent access to the customer's premise.

2.1.3 Equipment or meter failure or malfunction with no reliable information retained by the meter.

2.1.4 Labor unavailability due to circumstances such as unforeseen illness, natural disasters, or other extreme events.

2.1.5 Meter tampering or energy diversion resulting in a lack of accurate metered consumption information.

2.1.6 An electronic meter reading is obtained, but the data cannot be transferred to a billing computer.

2.1.7 Only a partial read for a meter (for example, the total kWh read is obtained from a time-of-use meter, but on-peak kWh and/or kW reads are unavailable). Company will use the read available, and estimate the missing read(s).

2.2 The following defines certain conditions under which a bill is not considered estimated:

2.2.1 A bill based on an actual kWh read, following an estimated bill. This is considered a "true-up" bill and has an explanation of "true-up" on the bill.

2.2.2 Rate changes in the middle of the billing cycle.

2.2.3 A meter failure or malfunction which does not prevent the meter from accurately recording customer usage or from being read.

2.2.4 The meter read is not available using electronic meter reading devices, but data is obtained from a visual meter reading.

2.2.5 Meter reading information is not available because the service is provided on an un-metered basis.

2.2.6 Unbundled service for direct access customers is provided on the basis of load profiles in accordance with ACC regulations rather than using interval data metering.

2.2.7 When Company determines a meter is misread, but the actual read on the meter at the time it was read can be determined, Company makes a manual correction to the incorrect read. This includes, but is not limited to, the following examples:

2.2.7.1 A shut-off read is obtained, and on the same day the monthly meter read is taken and is higher by 1 kWh. The monthly meter read is changed to the same read as the shut off read.

2.2.7.2 The serviceman enters a shut-off or turn-on read and then calls into the office to say he entered the read for the wrong address. The correct reads are entered for the appropriate addresses.

2.2.7.3 Accurate consumption information can be obtained from load research meters.

SERVICE SCHEDULE 8
BILL ESTIMATION

2.2.8 A bill is estimated, and then rebilled when an actual read is obtained for the same billing period. The first bill is considered an estimated bill and is coded as such. The subsequent bill is considered a corrected bill and is not coded as an estimate, but does contain "corrected bill" language.

3. BILL ESTIMATION METHODS

The following section describes the estimation methods used to estimate energy consumption and demand for most instances. Estimation techniques required where special circumstances exist, such as initial bills, are also described. In general, the estimation methodologies utilize historical data.

3.1 ENERGY ESTIMATION (kWh)

For energy estimation, the following hierarchy is used: 1) The estimate will be based on the specific prior month's energy consumption unless that month was an initial bill. 2) If the prior month's customer-specific energy consumption is not available or was an initial bill, the estimate will be based on the customer-specific energy consumption for the same month in the prior year. 3) If the customer-specific prior month or same month last year energy consumption is unavailable but adequate seasonal customer history exists, energy consumption will be estimated based on daily usage during six months of the same season. 4) If specific energy consumption is not available, the estimate will be based on the prior month's energy consumption at that premise unless that month was an initial bill. 5) If prior month's premise energy consumption is not available or was an initial bill, the premise energy consumption for the same month in the prior year will be used to estimate consumption. 6) If premise-specific prior month or same month last year is unavailable but adequate seasonal premise history exists, energy consumption will be estimated based on daily usage during six months of the same season. 7) When adequate customer or premise history is not available, the estimate is based on the customer class average usage found in Section 3.3.1.

For customers served under time-of-use schedules, the hierarchy listed above will be utilized to develop the estimated on-peak and off-peak energy consumption.

For customers served under rate schedules EPR-2 and EPR-5, the hierarchy listed above will be used to estimate the energy consumed by the Customer. Section 3.1.2 below shall be used to estimate any excess energy purchased by the Utility.

For bill estimation purposes, the Summer Season is defined as May through October and the Winter Season is defined as November through April.

The energy estimation methods are described in detail below.

Previous Month Method
Estimated energy usage is calculated as follows:

1. Determine the number of days for the previous month's billing period.

SERVICE SCHEDULE 8
BILL ESTIMATION

2. Determine the kWh for the previous month's billing period.

3. Divide the previous month kWh by the previous month number of days to determine p~~P~~revious m~~M~~onth per d~~D~~ay u~~U~~sage.

4. Multiply the p~~P~~revious m~~M~~onth per d~~Day~~ u~~U~~sage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

Same Month Prior Year Method
Estimated energy is calculated as follows:

1. Determine the number of days for the same month of the previous year's billing period.

2. Determine the kWh for the same month of the previous year's billing period.

3. Divide the same month prior year's kWh by the same month prior year's number of days to get s~~S~~ame m~~M~~onth p~~P~~rior y~~Y~~ear per d~~D~~ay u~~U~~sage.

4. Multiply the s~~S~~ame m~~M~~onth p~~P~~rior y~~Y~~ear per d~~D~~ay usage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

Seasonal Average Method

Estimated energy is calculated as follows:

Where there is sufficient seasonal history (the number of days billed in the season is between 165 and 195 days), energy is estimated by calculating the average use per day for the same season as the billing period with the missing read. The resulting per day usage is multiplied by the number of days in the missing-read billing period to yield the usage estimate for the billing period. Seasonal average is calculated as follows:

1. Determine the total number of days from each of the previous six same-season months to yield s~~S~~easonal t~~T~~otal d~~D~~ays.

2. Add the kWh from each of the previous six same-season months to yield s~~S~~easonal t~~T~~otal kWh.

3. Divide s~~S~~easonal t~~T~~otal kWh by s~~S~~easonal t~~T~~otal d~~D~~ays to yield the s~~S~~easonal p~~P~~er d~~D~~ay u~~U~~sage.

4. Multiply the s~~S~~easonal p~~P~~er d~~D~~ay u~~U~~sage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

SERVICE SCHEDULE 8
BILL ESTIMATION

Class Average Method

Estimated energy usage is calculated as follows:

Where neither customer nor premise history is available, energy is estimated by calculating the average use per day for customer served under the same rate schedule. The resulting per day usage is multiplied by the number of days in the missing-read billing period to yield the usage estimate for the billing period.

3.1.1 TIME-OF-USE AND SEASONAL ESTIMATION (kWh):

If the rate for the estimated billing period is a time-of-use rate and sufficient time-of-use history does not exist for a customer or premise, on-peak energy usage is allocated as follows:

	Summer (May through October)	Winter (November through April)
Residential		
ET-1	40%	30%
ET-2	25%	16%
ECT-1R	40%	30%
ECT-2	23%	16%
Non-Residential		
All	40%	30%

NOTE: The percentages specified above will also apply for seasonal estimation of Customer-owned on-site distributed generators to include both the energy consumed by the Customer and any excess energy purchased by the utility.

Seasonal on-peak energy percentages listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater then 5%.

3.1.2 ENERGY ESTIMATION FOR CUSTOMER-OWNED ON-SITE DISTRIBUTED GENERATORS

For energy estimation for Customer-owned on-site distributed generators, the following hierarchy is used: 1) The estimate will be based on each generators previous month's energy output unless that month was an initial bill. 2) If the prior month's generator-specific energy output is not available or was an initial bill, the estimate will be based on the generator-specific energy output for the same month in the prior year. 3) If similar generator output is not available, the estimate will be based on the prior month's generation output at that premise unless that month was an initial bill. 4) If prior month's premise generator output is not available or was an initial bill, the premise generator output for the same month in the prior year will be used to estimate generator output. 5) If premise-specific prior month or same month last year generator output is

unavailable but adequate seasonal premise generation output history exists, energy output will be estimated based on daily generation output during six months of the same season. 6) If the generator-specific prior month or same month last year energy output is unavailable but adequate seasonal history exists for a similar type of generator, energy output will be estimated based on the similar generator's output during six months of the same season. 7) When adequate Customer or similar generator output history is not available, the generator estimate is based on a 50% availability factor for the month (20% for PV systems).

For customers served under time-of-use schedules, the hierarchy listed above will be utilized to develop the estimated on-peak and off-peak energy consumption.

3.2 DEMAND ESTIMATION

For those accounts where the missing read period is billed on a demand rate and the missing read billing period is not for an initial bill, demand is estimated using the following hierarchy:

3.2.1 If it is the same customer, use the prior month's demand unless that demand was estimated or is for an initial bill.

3.2.2 If it is the same customer, but the prior month's customer-specific demand is not available or was estimated or was an initial bill, use the customer-specific demand read from the same billing month a year ago, unless that demand was estimated or is for an initial bill.

3.2.3 If the bill for the same month of the prior year was not for the same customer, or was estimated or for an initial bill, use the premise demand read for the prior month, unless that demand was estimated or is for an initial bill.

3.2.4 If the prior month's premise demand was estimated or was an initial bill, use the premise demand read from the same billing month of the prior year, unless that demand was estimated or was for an initial bill.

3.2.5 For purposes of this Section 3.2., a demand read is considered "estimated" if the demand was not reset the prior month (or any time thereafter) and the demand read is not greater than the prior month's demand read which was not reset.

3.2.6 If none of the above is applicable, apply the rate schedule load factor percentage to the appropriate kWh. The rate schedule load factor percentages are:

Residential:	Load Factor %
EC-1	35%
ECT-1R	42%
ECT-2	46%
Non-residential:	
All	50%

SERVICE SCHEDULE 8
BILL ESTIMATION

Load factors listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater than 5%.

3.2.7 From time to time, meter reader may be unable to reset demand readings. When this occurs the readings are noted as "Demand Not Reset."

3.2.7.1 In the month when the "Demand Not Reset" is noted, the kWh and kW are not estimates and are used for billing purposes.

3.2.7.2 In the following month, if the meter reader is able to reset the demand, the "Demand Not Reset" notation is removed.

1) If the kW reading is less than the reading for the previous month, the demand is used for billing purposes and is not an estimated demand.

2) If the demand reading is greater than the previous month when the "Demand Not Reset" was noted, the read demand is used.

3) If the demand reading is equal to the demand reading when the "Demand Not Reset" was noted, demand will be estimated using the procedures described in previous sections of this schedule.

3.2.8 DEMAND ESTIMATION FOR CUSTOMER-OWNED DISTRIBUTED GENERATORS

For those accounts where the missing read period is billed on a demand rate and the missing read billing period is not for an initial bill, demand is estimated using the following hierarchy:

3.2.8.1 If it is the same customer, use the prior month's demand from the Customer-owned generator unless that demand was estimated or is for an initial bill.

3.2.8.2 If it is the same customer, but the prior month's customer-specific demand from the generator is not available or was estimated or was an initial bill, use the customer-specific demand on the generator from the same billing month a year ago, unless that demand was estimated or is for an initial bill.

3.2.8.3 If the demand on the generator for the same month of the prior year was not for the same customer, or was estimated or for an initial bill, use the premise generator demand read for the prior month, unless that demand was estimated or is for an initial bill.

3.2.8.4 If the prior month's premise demand from the generator was estimated or was an initial bill, use the premise demand from the generator from the same billing month of the prior year.

SERVICE SCHEDULE 8
BILL ESTIMATION

3.2.8.5 For purposes of this Section 3.2., a demand read on the generator is considered "estimated" if the demand was not reset the prior month (or any time thereafter) and the demand read on the generator is not greater than the prior month's demand read which was not reset.

3.2.8.6 If none of the above is applicable, apply the rate schedule load factor percentage to the appropriate kWh. The rate schedule load factor percentages are:

Residential:	Load Factor %
EC-1	35%
ECT-1R	42%
ECT-2	46%
Non-residential:	
All	50%

Load factors listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater than 5%.

3.2.8.7 From time to time, meter reader may be unable to reset demand readings. When this occurs the readings are noted as "Demand Not Reset."

3.2.8.7.1 In the month when the "Demand Not Reset" is noted, the kWh and kW are not estimates and are used for billing purposes.

3.2.8.7.2 In the following month, if the meter reader is able to reset the demand on the generator, the "Demand Not Reset" notation is removed.

1) If the kW reading is less than the reading for the previous month, the demand on the generator is used for billing purposes and is not an estimated demand.

2) If the demand reading on the generator is greater than the previous month when the "Demand Not Reset" was noted, the read demand is used.

3) If the demand reading is equal to the demand reading when the "Demand Not Reset" was noted, demand will be estimated using the procedures described in previous sections of this schedule.

3.3 INITIAL BILL

An initial bill is the first bill a customer receives for a premise. Examples of an initial bill include a new meter set where no service has previously been provided, or a previously occupied premise that is now in the new connecting customer's name.

SERVICE SCHEDULE 8
BILL ESTIMATION

If the billing period for an initial bill is fewer than 11 days and no read was obtained, the customer is billed only a daily basic service charge, and any energy used during this period is included in the following month's billing period usage. If the billing period is 11 or more days, the bill is estimated as follows:

3.3.1 ENERGY USAGE (kWh):

If there is no usage history for the premise, a "minimum usage" estimate is multiplied by the number of days in the missing read billing period. The difference in energy used during this period and the "minimum usage" estimate is included in the following month's billing period usage. The "minimum usage" estimates for total kWh are:

Residential:	
E-12 and E-10	23 kWh per day
EC-1	55 kWh per day
ET-1 and ET-2	41 kWh per day
ECT-1R and ECT-2	66 kWh per day
Non-residential:	
Under 20 kW	45 kWh per day
Over 20 kW	1,156 kWh per day

NOTE: The minimum usage estimates specified above also apply to energy consumed by the Customer under rate schedules EPR-2 and EPR-5. Excess energy purchased by the utility will be estimated at zero for the initial bill.

Initial bill minimum energy usage estimates for total kWh listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater then 5%.

If there is usage history for the premise, energy will be estimated using the applicable method in Section 3.1. If there is no on-peak usage history for the premise, the allocations found in Section 3.1.1 will be utilized.

3.3.2 DEMAND (kW):
For those accounts where the missing read period is billed on a demand rate, demand is estimated as follows:

For initial bills fewer than 11 days, no demand charge is billed.

For initial bills 11 or more days, the kW is estimated using the same hierarchy as indicated in Section 3.2.

3.4 ADVANCED METER INFRASTRUCTURE (AMI) METERS

When a missing read occurs on an account with an AMI meter, an initial attempt to estimate will be performed using partial month data as available. AMI meter data is normally collected on a daily basis, and therefore would be used to compute an estimate for the billing month, even if some of these daily reads are missing.

SERVICE SCHEDULE 8
BILL ESTIMATION

3.4.1 For initial and normal bills of 11-24 days:

If the latest AMI meter data is available with a meter reading of 11 or more days since the last read date for the previous billing month:

1) Review the daily AMI incremental reads to determine the total energy consumption, on-peak percentage and demand for the billing month. Use reads from the latest AMI data to determine a per-day usage value and multiply by the number of days in the current billing period to yield the estimates for total and on-peak usage.

2) If the AMI meter data is unavailable use the estimation methods for non-AMI meters.

3.4.2 For initial and normal bills of 10 or less days, use the estimation methods described in Section 3.3.

3.5 DEAD OR FAILING METER

For accounts where it is determined the meter is dead or failing, no adjustment to the bill will be made until the new meter is in place at least 11 days. Then the usage for the previous month(s) is to be determined by taking the lower of the per day usage calculated from the new meter, less 3% (plus 3% for estimating customer-owned on-site generation bought by Utility), or the Same Month Prior Year Method described in Section 3.1. Charges for underbillings of dead or failing meters will be limited to three months for residential accounts and six months for non-residential accounts, in accordance with Schedule 1 Section 4.3. In instances where Company believes the customer's usage patterns were different during the dead or failing meter period than those being used to estimate, Company may adjust its estimate downward from either method.

3.6 ENERGY DIVERSION OR METER TAMPERING

In instances where energy diversion or meter tampering has occurred, meter reads from the ~~customer's~~ meter will not accurately reflect all of the energy usage. Energy consumption for the period during which the diversion or meter tampering occurred shall be estimated by calculating a per day usage based on the best available information. This may include 1) metered data obtained from an auxiliary meter installed during the diversion investigation; 2) meter information obtained from the customer's meter after the diversion or meter tampering was discovered by Company and stopped; and 3) consumption history for the customer or site prior to when the diversion or meter tampering began.

In some instances, the estimated consumption based on per day usage may be less than what the ~~customer's~~ meter actually registered during the time period. In those cases, the actual usage will be used in the calculation of the total energy diversion or meter tampering back bill.

3.7 NON-CUSTOMER INFORMATION SYSTEM ESTIMATES

SERVICE SCHEDULE 8
BILL ESTIMATION

In some instances, an account is coded to not be automatically estimated by Company's Customer Information System (CIS). This occurs when, due to special circumstances of the account (such as: served at substation voltage, receives a power allowance from a federal agency, partial requirements/self-generation, etc.), manual intervention in the billing process is required. For those accounts which are coded to not be automatically estimated by the CIS, additional attempts may be made to obtain meter readings which will be used for billing. If reads are not obtained, then energy and demand will be estimated, using the applicable methods described in this Schedule.

3.8 REBILLS OF PREVIOUS ESTIMATES

In instances where the reads from the previous month are estimated and a subsequent actual read is obtained, the following "true-up" is performed.

3.8.1 ENERGY USAGE
If the actual read following an estimated read is either lower than the estimated read, or, in Company's opinion, considerably higher than the previously estimated read(s), then per day usage is calculated using the difference in kWh between the last actual read and the current month actual read. The per day usage is multiplied by the number of days in each estimated month and each affected month is rebilled using the new per day usage kWh.

3.8.2 DEMAND
If the actual demand read obtained after an estimate is lower than the estimated demand read, the previous month(s) estimated demand read(s) are lowered to the subsequent actual demand read.

The estimates used in this Section 3.8 take precedence over the estimating methods described elsewhere in this Service Schedule.

SERVICE SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, et seq., referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers shall obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services (when permitted ~~by the Rules)~~ as specified here~~with~~in.

1. General Terms

1.1 Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

1.1.1 Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.

1.1.2 Service Account - Unless otherwise stated, all references to "Service Account" in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).

1.1.3 Local Arizona Time – All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

2.1 Non-Discrimination

2.1.1 Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, Company shall not:

2.1.1.1 Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or

2.1.1.2 Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2 Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1 Timeliness, Due Diligence and Security Requirements

3.1.1 ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to Company in a timely manner.

3.1.2 ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2 Arrangements with ESP Customers

ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3 Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4 Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.

3.5 Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1 ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute Company charges or for tariff applicability.

3.5.2 Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6 Interval Metering

3.6.1 "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.

3.6.2. Company shall determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7 Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.

3.8 Statistical Load Profiles

Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10 Liability In Connection With ESP Services

3.10.1 "Damages" shall include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.

3.10.2 Company shall not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in Company's Schedule #1.

3.10.3 Company shall not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4 Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.

3.10.5 An ESP is not a Company agent for any purpose. Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances shall Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

4.1 Customer Inquiries – For customers requesting information on Direct Access, Company shall make available the following information:

4.1.1 Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by Company.

4.2 Access to Customer Usage Data. For Company customers on Standard Offer Service, Company shall provide customer specific usage data to ESP or to Customer, subject to the following provisions:

4.2.1 ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data at rates approved by the ACC.

4.2.2 Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.

4.3 Customer Inquires Concerning Billing Related Issues

4.3.1 Customer inquiries concerning Company charges or services shall be directed to Company.

4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.

4.4 Customer Inquiries Related to Emergency Situations and Outages

4.4.1 Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.

4.4.2 Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.

APS

SERVICE SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

5. ESP Service Establishment

5.1 Before the ESP or its agents can offer Direct Access services in Company's distribution service territory they must meet the applicable provisions as listed:

5.1.1 All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.

5.1.2 All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.

5.1.3 Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5 All ESPs must satisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1 The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.

5.1.5.2 The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.

5.1.5.3 The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.

5.1.5.4 The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. Alternative arrangements may be allowed at Company's option.

5.1.6 For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7 Compliance testing will be required for a MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to

the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.

6. Direct Access Service Request (DASR)

6.1 A DASR is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with Company, if required, and shall have successfully completed data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4 A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.

6.5 Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site (http://esp.apsc.com).

6.6 DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by Company.

6.7 Once the DASR is submitted, the following timeframes will apply:

6.7.1 Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2 When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).

6.7.2.1 When Company is acting as the MSP, Company shall perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days prior to the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.

6.7.2.2 When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.

6.8 DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates shall be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10 If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

6.11 Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12 Customers returning to Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the DASR on behalf of the customer.

6.13 ESPs requesting to return a Direct Access customer to Company Standard Offer service shall submit a TS DASR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14 Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access service. Direct Access customers returning to Company Standard Offer service may be subject to the RCDAC-1.

6.15 Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16 A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the

necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17 Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18 Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer shall not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 Subject to availability, and pursuant to the terms in the ESP Service Acquisition Agreement, this Schedule 10, and applicable tariffs and the restrictions therein, ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company shall bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company shall comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP shall receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2 The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1 Bills under this option will be rendered once a month. Nothing contained in this Schedule shall limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2 Except as provided in Section 7.2.4.1, Company shall require that all ESP and Company charges be based on the same billing period data.

7.2.4.3 ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that Company charges were previously billed.

7.2.4.4 ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5 Restrictions

Company UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3 ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations:

7.3.2.1 Company shall calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company shall provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP shall include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP shall comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company shall continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) shall resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company shall be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company shall transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP shall apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP shall be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company shall remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP shall pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If

an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments shall be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account shall be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP shall be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company shall not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

APS

SERVICE SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company shall notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges prior to disconnecting electric service to the Customer. Company shall further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company shall reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company shall notify the ESP of a Customer's reconnection.

7.9.3 Company shall not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10 Involuntary Service Changes

7.10.1 A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1 The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5 The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2 Change of Service Election in Exigent Circumstances

APS

SERVICE SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company shall provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to Customer other than as provided in Section 4.4.2.

7.10.3 Change in Service Election Absent Exigent Circumstances

7.10.3.1 In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2) or involve an ESP's unauthorized energy use, Company shall notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1 The nature of the alleged failure;

7.10.3.1.2 The actions necessary to remedy the failure;

7.10.3.1.3 The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2 The ESP shall have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP

following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4 Termination of ESP Consolidated Billing

7.10.4.1 Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1 The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2 If the ESP fails to pay Company (or dispute payment pursuant to the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.1.3 If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.2 Upon termination of ESP Consolidated Billing pursuant to Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs-associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

7.10.5 Termination of Company UDC Consolidated Billing

7.10.5.1 Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6 Upon termination of ESP Direct Access services pursuant to Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company shall provide such services, until such time that Customer makes an election.

7.10.7 Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11 ESP Security Deposits

7.11.1 Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2 The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3 Security deposits required pursuant to Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4 Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to Section 7.11

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MRSP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for ~~Residential Load Profiled~~all Direct Access Customers.

8.2.1.1 If the ESP subcontracts with the UDC for Meter Services they must subcontract for both Metering and Meter Reading Services. The ESP shall remain responsible for all cost associated with Metering, Meter Installation, Meter Communications and other MSRP related cost. All such cost shall be authorized by the ACC.

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party or the UDC. If the ESP sub-contracts any of the components of these services to a third party or UDC, the ESP shall, for the purposes of this Schedule, remain responsible for the services including communication equipment, meter reading equipment and associated maintenance necessary to obtain reads from specialized meters that may be required by a Direct Access Customers.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party or UDC assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test ANSI 57.13 Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test
1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs

incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and Company shall use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent shall install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent shall inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent shall return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

APS

SERVICE SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements.

Company shall perform a preinstallation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC shall coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 If the ESP or customer owns the meter, the ESP must own the CTs, PTs, and associated equipment, except as provided in Section 8.12.3. The ESP may purchase existing CTs and PTs and associated metering equipment from Company at depreciated original cost.

8.12.3 The following provisions apply to the ownership of CTs and PTs.

8.12.3.1 For distribution voltages up to 25kV, the ESP or Company shall own the CTs and PTs. For transmission primary voltages (over 25kV), the CTs and PTs shall be owned by Company. ESP owned CTs and PTs must meet Company specifications. No CTs and PTs or associated metering equipment shall be set or allowed to remain in service if it is determined that the CTs and PTs or their associated equipment does not meet Company's approved specifications, as set forth in Company's Electric Service Requirements Manual in place at the time of installation.

8.12.4 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation and associated cost. Company may optionally provide meter installation pursuant to the ~~Rules~~provisions of this Service Schedule.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents shall:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they shall meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP shall coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

APS

SERVICE SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next scheduled read date. MRSP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.2 Both Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.4 The MRSP shall provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs shall read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters

8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time shall be accurate.

8.16.1.3 All meter reading data shall be validated pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Pursuant to guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data shall be available by 3:00 p.m. Local Arizona Time (MST) on the third working day after the scheduled read date. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP shall be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Prior to performing MRSP services in Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions:

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

APS

SERVICE SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to section 7.10.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

SERVICE SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) will provide specialized metering upon customer request, provided the customer agrees to the following conditions:

1. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR meter ~~and~~ with KYZ pulse and/or modem options (including associated interfaces) ~~meters~~. ~~The customer must specify whether a modem will be required.~~

2. If the customer requests a meter with a modem option, the customer will be required to install coil of communication cable within ~~communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within~~ five ~~to ten~~ feet of the meter panel location and in such a manner that will provide for ease of attachment ~~of the jack~~ to the meter panel by Company. The phone line must be installed prior to the installation of the meter and shall be located in such a manner as to not impede access to the metering equipment, the interior or exterior of the metering compartment or other utility access panels. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. If a customer requests kWh pulses, Company shall furnish and install a customer pulse interface and enclosure. Connections made by the customer to the customer pulse interface shall not impede access to metering equipment, the interior or exterior of the metering compartment or other utility access panels. ~~an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.~~

4. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

   Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

   Company will retain ownership of all meters and Company installed metering equipment.

SERVICE SCHEDULE 15
CONDITIONS GOVERNING THE
PROVISION OF SPECIALIZED METERING

If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the customer stop the operation or in any way affect or interfere with the operation of the customer pulse interface ~~isolation relay~~ and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the customer's demand control or other equipment. However, Company will make a good faith effort to notify the customer prior to any interruption of the specialized metering circuit.

7. The possible failure or malfunction of an ~~isolation relay~~KYZ pulse output or interface and subsequent loss of kWh contact closures to the customer's control equipment shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the kWh and demand record for billing purposes.

8. The accuracy of the customer's equipment is entirely the responsibility of the customer. Should the customer's equipment malfunction, Company will reasonably cooperate with the customer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the customer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides pulse values in kWh, customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the customer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the customer.

12. Upon request by Company, the customer shall make available to Company monthly load analysis information.

13. References to electric kWh pulses above shall mean dry KYZ ~~isolation relay~~ contact closures only; the customer is required to furnish operating voltage service. ~~Isolation relay~~KYZ contacts are rated for and shall not be wetted beyond a maximum of 100 milliampere and 120 volts DC or AC rms. ~~5 amps, 28 volts DC or 120 volts AC.~~

14. The customer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of specialized metering.

SERVICE SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

16. Prior written approval by an authorized Company representative is required before electric kWh pulses service may be implemented.

Charles A. Miessner

DIRECT TESTIMONY OF CHARLES A. MIESSNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

June 2008

Table of Contents

I. Introduction 1
II. Summary of Testimony 1
III. Demand Response Pricing 2
IV. Super Peak Time-of-Use Pricing 9
V. Critical Peak Pricing 10
VI. Implementation Considerations 13
VII. Conclusion 14
Proposed Schedule ET-SP ..... Attachment CAM-1
Proposed Schedule GS-CPP ..... Attachment CAM-2

DIRECT TESTIMONY OF CHARLES A. MIESSNER

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Charles A. Miessner, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Supervisor of Pricing for Arizona Public Service Company ("APS" or "Company").

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. I have twenty five years experience in the energy industry in the areas of pricing, regulatory policy and planning. Prior to my current position at APS, I served as Director of Pricing and Regulation at New West Energy. I have also worked in related positions for Carolina Power and Light, Tucson Electric Power, and AES.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's proposals for two new demand response pricing programs, which include a residential super peak time-of-use rate and a critical peak pricing program for general service customers.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my Testimony, I describe the general concept of demand response pricing programs, which includes time-of-use rates ("TOU"), critical peak pricing ("CPP"), real time pricing ("RTP") and other concepts; I discuss the difference between static and dynamic programs and the benefits of each option; I outline the research that the Company is conducting to formulate a demand response strategy, and I

summarize the findings and recommendations from the research results.

The Company is recommending that a new TOU rate be offered for residential customers, which provides higher peak price signals during the highest summer peak hours. This concept will be tested to see if it can provide similar benefits to CPP, but with lower implementation costs and higher customer acceptance.

The Company is also recommending that a CPP program be offered to general service customers. The program will test the potential load reduction during critical hours, customer acceptance, and will assess implementation cost issues.

The Company is not recommending a RTP program at this time because APS does not believe that this concept is likely to be as beneficial to APS and its customers compared to other demand response pricing options.

III. DEMAND RESPONSE PRICING

Q. IN THE COMPANY'S LAST RATE CASE, WHAT DID THE COMMISSION ORDER CONCERNING DEMAND RESPONSE PROGRAMS?

A. In Decision No. 69663 (June 28, 2007), the Commission ordered the Company to conduct a study on demand response and to submit one or more programs based upon that study. The study and program are to be submitted within one year of the Decision, which is June 2008. The Commission also ordered the Company to consider a CPP program and offer it in its next rate filing.

Q. HOW DOES THE COMPANY INTEND TO ADDRESS THE COMMISSION'S DIRECTION CONCERNING DEMAND RESPONSE?

A. As more fully described below, the Company is currently conducting research concerning demand response pricing programs. APS has investigated rates and

programs offered both by other utilities and independent system operators. The Company has also conducted marketing research on various pricing concepts. In addition, the Company hired an industry consultant on pricing and demand response programs to assess the potential benefits of demand response pricing programs. Pursuant to Decision No. 69663, the Company will be filing as a compliance item in that proceeding, the study that is due June of 2008. While this research is continuing, the Company believes that it has enough information at this time to recommend new demand response pricing programs, including CPP, in the instant proceeding.

Q. WHAT IS DEMAND RESPONSE?

A. Demand response is a rate or program that encourages customers to reduce usage when electricity is in short supply or expensive to produce. For example, these could be times of extreme temperatures, high loads, generation outages or transmission outages. Demand response programs can be pricing programs, where the customer faces high prices during critical periods in exchange for lower prices during other time periods, or quantity programs in which the customer agrees to curtail load during critical periods. Some programs are a hybrid mixture of pricing and quantity programs. Demand response programs can be beneficial to all customers if they allow the Company to avoid high energy costs during peak hours and reduce the need to obtain capacity resources in the future.

Q. COULD YOU GIVE SOME EXAMPLES OF DEMAND RESPONSE PROGRAMS?

A. Yes. Demand response pricing programs include, for example, TOU, CPP, and RTP. TOU rates provide higher prices during peak periods when the cost to provide service is greater and lower prices during off-peak periods when the cost to

the Company to provide service is less. CPP is a TOU rate which also provides a very high price during a limited number of critical hours on critical days. The customer is typically notified a day in advance when a critical day will occur and can respond by reducing consumption during the specified hours to avoid paying the high critical peak price. RTP programs utilize hourly prices, which the utility posts on a day-ahead basis. These prices are either applied to a customer's total usage or to deviations in usage from an established customer usage baseline.

Examples of demand response quantity programs include direct load control and curtailable programs. Load control programs entail the utility switching off or cycling a customer's equipment such as air-conditioners, water heaters, pool pumps, chillers or refrigeration equipment. Curtailable programs involve the customer committing to reduce a specified amount of load during critical periods as requested by the utility. Demand bidding is an example of a hybrid program, where a customer receives notification of day-ahead prices and bids an amount of demand reduction for the next day.

Q. WHAT IS MEANT BY A "DYNAMIC" VERSUS "STATIC" DEMAND RESPONSE PROGRAM?

A. Demand response programs can be "dynamic" or "static" or have elements of each. A dynamic program means that some feature of the program, such as the prices or critical time periods, can be changed to react to critical events, such as high wholesale prices, or electrical supply outages. Conversely, the features of a static program are set ahead of time, for example in a rate schedule, and are not changed on a day-to-day basis.

TOU rates are typically static in nature, that is the prices and on-peak time periods are set ahead of time in a rate schedule and are not changed in real time. CPP typically has a static price but a dynamic time period. The utility can call a

critical event a day in advance as needed, but the prices for the critical day are set well in advance in a rate schedule. On the other hand, RTP provides dynamic hourly prices, which may be determined one day in advance.

Demand response quantity programs typically have dynamic time periods, but have static prices or amounts paid for demand reduction. For example, load control programs can be activated in real time as needed with short notice, but the amount paid to the customer for the demand reduction is set in advance in a rate schedule.

Q. WHAT ARE THE ADVANTAGES OF STATIC AND DYNAMIC DEMAND RESPONSE PROGRAMS?

A. Static prices and dynamic prices each have their own advantages. For example, let's compare some of the potential advantages of TOU rates and CPP. TOU rates provide more predictable price signals to customers compared with CPP, while the latter provides more flexibility to respond to critical events. CPP can provide a very high critical price because it is focused on a few critical hours, typically less than 100 hours per year. TOU rates, on the other hand, typically offer a higher potential customer savings because the peak prices, although typically lower than CPP, apply to many more hours in the year. CPP can result in a higher load reduction during critical hours compared with TOU, primarily due to the higher CPP prices, and can appeal to those customers who are able to significantly reduce consumption during a few critical days. However, TOU can result in more reliable load reduction over a longer time period because customers tend to habitually respond to peak prices on a daily basis, rather than just on a few days per month with CPP, and would appeal to customers who prefer to shift consumption to the off-peak hours on a daily basis.

Q. WHAT SPECIFIC RESEARCH HAS THE COMPANY PERFORMED CONCERNING DEMAND RESPONSE PRICING PROGRAMS?

A. The Company has conducted a number of research initiatives concerning demand response pricing programs. First, APS investigated demand response pricing programs which are offered by other utilities and independent system operators. The Company reviewed the rate schedules offered by investor-owned and public power utilities to identify current demand response rate offerings or pilot programs. Next, the Company reviewed government surveys of utility demand response programs and researched industry studies of various pilot projects.

After the initial scoping research was complete, the Company developed a priority list of demand response pricing concepts and conducted qualitative and quantitative marketing research on these programs. The marketing research included focus groups and surveys of residential, general service, and large "key-account" customers. Next, the Company hired an industry consultant on pricing and demand response programs to develop an independent list of potential programs and to perform a first-level assessment of potential program benefits on the combined program list.

Q. COULD YOU PROVIDE SOME EXAMPLES OF SPECIFIC PROGRAMS OR RESEARCH STUDIES THAT THE COMPANY ANALYZED AS PART OF THIS INVESTIGATION?

A. Yes. The Company reviewed governmental surveys of demand response programs including recent studies performed by the U.S. Environmental Protection Agency[1] and the Federal Energy Regulatory Commission.[2] In addition the Company

---

1 ENERGY & ENVIRONMENTAL ECONOMICS, A SURVEY OF TIME-OF-USE (TOU) PRICING AND DEMAND-RESPONSE (DR) PROGRAMS (2006).

2 FEDERAL ENERGY REGULATORY COMM'N, DOCKET NO. AD06-2-000, ASSESSMENT OF DEMAND RESPONSE & ADVANCED METERING STAFF REPORT (2006).

reviewed major demand response programs and pilot studies including: a California pilot for critical peak pricing and time-of-use rates[3] and the Ontario Energy Board pilot for critical peak pricing, critical peak rebates and time-of-use rates.[4] Finally, the Company reviewed Georgia Power's commercial real-time pricing program, Commonwealth Edison's RTP program for residential customers and the critical peak pricing program offered by Gulf Power.

Q. WHAT ARE THE KEY RESULTS OF THE COMPANY'S ANALYSIS TO DATE?

A. Based on the Company's analysis of other programs as well as the marketing research and benefits analysis described above, the Company has concluded the following:

- Several demand response concepts, including TOU, CPP, and RTP have resulted in moderate to high levels of load reduction during summer peak periods, depending on the particular utilities' customer profile.
- TOU is available for more summer hours, compared to CPP, which may provide more consistent load reduction over time and have a greater impact on reducing capacity costs.
- TOU rates are likely to have a higher customer acceptance compared with CPP and RTP for residential customers and are typically less expensive to implement and operate compared with CPP and RTP.
- CPP programs are "dispatchable" and could provide load response during the most critical hours. However, CPP may appeal to a select group of customers that have the ability to reduce their usage on short notice.

---

3 CHARLES RIVER ASSOCIATES, IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT (2005).

4 ONTARIO ENERGY BOARD, SMART PRICE PILOT FINAL REPORT (2007).

- RTP programs are better targeted to commercial and industrial customers who can manage their usage to reduce the risks of being billed according to hourly energy prices.
- RTP programs are better suited for utilities with highly variable hourly energy prices and can have significant implementation costs, but are generally less effective in reducing peak load than either CPP or TOU.

Q. BASED ON THESE FINDINGS, WHAT DOES THE COMPANY RECOMMEND CONCERNING DEMAND RESPONSE PRICING?

A. The Company recommends the following strategy:

- A TOU option for residential customers that is more focused on critical peak hours.
- A CPP concept for general service customers, such as commercial, industrial, and pumping customers, who may be able to reduce a substantial amount of load during a limited number of critical hours per year.
- Do not pursue RTP at this time, because CPP and TOU appear to be better suited for APS and its customers and are far less expensive to implement than RTP.

APS is currently conducting additional in-depth research on load impacts, avoided costs, customer savings and pricing analysis on some of the more promising demand response pricing concepts. While this research is continuing, the Company believes that it has enough information at this time to recommend new demand response programs in this case.

Q. IN FURTHERANCE OF THESE RECOMMENDTIONS, WHAT NEW DEMAND RESPONSE PROGRAMS IS APS PROPOSING IN THIS CASE?

A. The Company is proposing to offer two new demand response programs, which include a residential TOU rate with a super-peak price during summer afternoons and a CPP program for general service customers.

IV. SUPER PEAK TIME-OF-USE PRICING

Q. PLEASE DESCRIBE THE PROPOSED RESIDENTIAL TOU RATE WITH THE SUPER PEAK PRICE.

A. The Company is proposing a new residential TOU rate with a super peak price for the most critical summer hours. This rate will be similar to rate ET-2, with a 7-hour on-peak period, but will add a super peak price for weekday afternoons from 3:00 p.m. to 6:00 p.m. during June, July and August. The summer off-peak price will be discounted to off-set the higher super peak price. The customer has the opportunity to have lower monthly bills by reducing load during either the on-peak or super-peak periods, or both. It will be available to all residential customers who are served with advanced metering infrastructure ("AMI") meters. I discuss the status of the Company's AMI rollout program later in my testimony. The proposed Schedule ET-SP is provided as Attachment CAM-1 and also provided in the rate schedules filed in this rate application.

Q. IS THIS THE SAME THING AS CPP?

A. Not entirely. The Company's proposal is similar to CPP in that it charges a very high price during critical summer hours. However, the actual super peak hours occur every weekday afternoon June through August, rather than intermittently under CPP. The Company believes that the super peak TOU rate can potentially provide a number of benefits for residential customers compared with CPP.

Q. WHAT ARE SOME OF THE BENEFITS OF A SUPER PEAK TOU RATE COMPARED WITH CPP?

A. The Company believes that the proposed super peak TOU rate can be advantageous because: (1) it would target the same core critical hours that are likely to be targeted by CPP and will result in a sustained reduction in peak load compared to CPP; (2) it would provide a high price signal during those critical hours similar to

CPP; (3) the super-peak hours would be more consistent and predictable than the random callable days of CPP, and therefore, may result in greater customer participation and a more consistent customer response; and (4) the program can be implemented and administered at a lower cost compared with CPP. In addition, APS believes that this rate proposal will help the Company gauge the customer participation and potential response to critical peak prices.

V. CRITICAL PEAK PRICING

Q. IN THE LAST RATE CASE, THE COMMISSION ORDERED THE COMPANY TO PROPOSE CPP IN ITS NEXT RATE APPLICATION. IS APS PROPOSING ANY CPP RATE OPTIONS IN THIS CASE?

A. Yes. To test the concept of CPP and the customer's ability to reduce load during summer business hours, the Company is proposing a CPP program for general service customers, which the Company believes is the best group to target for CPP. Because this rate option has not been offered previously, the Company believes that this option should be limited at this time to 100 participants for a two-year trial period. The rate would be available to medium, large, and extra large general service and water pumping customers served on rate schedules E-32 M, E-32 L, E-32TOU M, E-32TOU L, E-34, E-35 and E-221. Eligible customers must be capable of reducing usage during critical periods by a minimum of 200 kW and have interval metering.

Q. PLEASE DESCRIBE THE CPP RATE SCHEDULE.

A. This rate schedule would provide a high price for critical hours as called by the Company with one day advance notice. The critical hours would be limited to 90 hours per year, 5 hours per day, and 18 days per year. A critical event could be called for any weekday, June through September. The customer would be charged

an additional critical peak price for consumption during each critical hour, but would be compensated through a discount based on the customer's monthly kWh consumption. The CPP price and the discount are designed to be revenue neutral for each of the eligible rate classes described above. A customer would have the opportunity to reduce its bills if it reduces usage during the critical hours because the customer would avoid paying the critical peak price, but still receive the monthly discount.

Critical events could be triggered by severe weather, high load, high wholesale prices, or a major generation or transmission outage as determined by the Company. Customers would be notified of a critical event in advance by 4:00 pm the day prior through a phone message and/or e-mail. The proposed Schedule GS-CPP is provided as Attachment CAM-2 and also provided in the rate schedules filed in this rate application.

Q. WHAT ARE THE CRITICAL HOURS?

A. Critical events may be invoked by the Company for the period 2 p.m. to 7 p.m., weekdays during June through September, excluding designated holidays. Each critical event will last the entire 2 p.m. to 7 p.m. period.

Q. HOW WOULD A CUSTOMER BE BILLED UNDER THIS RATE?

A. The participating customer would be billed according to their otherwise applicable rate schedule, for the eligible rate schedules listed above, including all of the adjustments. Schedule GS-CPP would be billed in addition to those rate schedules. The customer would receive an additional charge for their consumption during critical hours for the month. Customers would also receive a discount based on their remaining kWh consumption for the month.

Q. WHY RESTRICT PARTICIPATION IN THIS PROGRAM?

A. The Company believes it is prudent to initially restrict the participation in this

program for several reasons. First, the rate concept is new to APS and relatively new to the electric utility industry. While several utilities have piloted similar programs over the last few years, there has been little or no experience with CPP programs implemented on a large scale basis. Several key uncertainties remain with these programs including long-term customer acceptance of CPP, the adequacy of the typical bill savings, and the persistence of the customer's load response over time. Limiting the participation of the program would allow the Company to assess these uncertainties and test the viability of the program in the APS service territory. As previously discussed, the Company proposes to initially offer the rate to the first 100 eligible customers to apply for a period of two years. If successful, the program could be expanded and/or modified.

Second, because a large scale implementation of this program would require certain costs including metering systems, billing system upgrades, and other operational costs, a limited program would help ensure that customers are willing to participate in the program and actually reduce consumption during critical hours prior to the Company incurring such costs.

Moreover, the Company does not believe that the initial limitation of 100 customers will be overly restrictive. There are approximately 1,000 general service customers who would likely be eligible for the program. The initial 100 participant limit represents roughly 10 percent of the likely eligible customers. To help ensure ample participation in the program, the Company also proposes to be able to expand the eligibility of the program, at its discretion, with notification to the Commission. For example, if initial customer participation was low, the minimum load reduction requirement could be reduced to 100 kW in order to stimulate enrollment in the program.

Q. HOW WOULD THE COMPANY DETERMINE IF THE CUSTOMER IS ABLE TO REDUCE THEIR CONSUMPTION BY 200 KW OR MORE DURING CRITICAL PEAK HOURS?

A. The Company will work with interested customers to develop a plan for reducing load during critical hours. To be eligible for participation, a customer must submit a viable plan for reducing load by 200 kW or more, which must be approved by the Company.

VI. IMPLEMENTATION CONSIDERATIONS

Q. WHAT COSTS ARE ASSOCIATED WITH OFFERING THESE NEW DEMAND RESPONSE RATES?

A. The implementation costs for the residential super peak TOU rate and the general service CPP rate include incremental metering and communication system costs, customer service costs, upgrades to billing and customer information systems ("CIS"), and other costs of operating the programs.

CIS is a key driver, indeed a critical path, for implementing demand response rates. Any proposed changes will require programming and testing of CIS and related systems, which all interrelate to capture metered data, ensure that the customer is on the correct rate schedule with the correct meter, calculate the bill, present the bill format, allow for re-bills and corrections, schedule meter and service changes, provide customer service information and screens to advise customers about rate options, allow customers to assess rate options through the internet, post the revenue to the general ledger, and many other business functions. Most importantly, the systems must be tested to ensure that the billing is accurate and that the programming changes did not adversely impact any other part of the billing system.

Finally, the implementation of new demand response rates will require additional training of customer service personnel as well as additional resource

costs to interface with customers to answer customer inquiries, explain the advantages of the new rates, and enroll interested customers. Therefore, customer participation on the rates will not be available until approximately three months after approval by the Commission.

Q. PLEASE DESCRIBE WHAT STEPS THE COMPANY HAS TAKEN TO IMPLEMENT NEW METERING SYSTEMS TO ACCOMMODATE THESE NEW RATES.

A. The Company would implement the new demand response pricing programs through Interval Data Recording ("IDR") meters and AMI meters. AMI meters would provide the advantage of remote reading and programming, which would enable seasonal changes in on-peak hours without meter change outs, provide more flexibility and lower costs when customers switch from one rate to another. It also has the advantage of lower communication costs compared with IDR/cell phone technology. Currently, APS has approximately 125,000 AMI meters installed and is estimating to have approximately one million installed by 2012.

VII. CONCLUSION

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. APS is requesting the Commission to authorize the implementation of a new residential super peak TOU rate, Schedule ET-SP, and a new CPP program for general service customers, Schedule GS-CPP. The Company believes that these new demand response rates can encourage customers to reduce consumption during the most critical hours during the hot summer afternoons and early evenings thereby reducing costs to the Company and benefiting all customers. The rates will also provide an additional opportunity for customers to reduce their monthly electric bill. Due to the implementation requirements, these new offerings would be available approximately three months after approval by the Commission.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

RATE SCHEDULE ET-SP
RESIDENTIAL SERVICE TIME-OF-USE
TIME ADVANTAGE SUPER PEAK 7PM-NOON

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Additionally, this rate requires the Customer to have an Advanced Metering Infastructure meter, or AMI, in place at time of service.

APPLICATION

This rate schedule is applicable to all Standard Offer electric service required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services) and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.509 per day

Energy Charge:

June – August Billing Cycles (Super Peak Summer)
$0.49465 per kWh during Super-Peak hours, plus $0.24465 per kWh during On-Peak hours, plus $0.05259 per kWh during Off-Peak hours

May, September, and October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.24465 per kWh during On-Peak hours, plus $0.05259 per kWh during Off-Peak hours	$0.19842 per kWh during On-Peak hours, plus $0.05259 per kWh during Off-Peak hours

RATE SCHEDULE ET-SP
RESIDENTIAL SERVICE TIME-OF-USE
TIME ADVANTAGE SUPER PEAK 7PM-NOON

RATES (cont)

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$ 0.227	per day
Revenue Cycle Service Charges:		
Metering	$ 0.165	per day
Meter Reading	$ 0.055	per day
Billing	$ 0.062	per day
System Benefits Charge:	$ 0.00188	per kWh
Delivery Charge:	$ 0.02222	per kWh

Generation Charge:

June – August Billing Cycles (Super Peak Summer)
$0.47055 per kWh during Super-Peak hours, plus $0.22055 per kWh during On-Peak hours, plus $0.02849 per kWh during Off-Peak hours

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.22055 per kWh during On-Peak hours, plus $0.02849 per kWh during Off-Peak hours	$0.17432 per kWh during On-Peak hours, plus $0.02849 per kWh during Off-Peak hours

TIME PERIODS

The Super-Peak time period is 3 p.m. to 6 p.m. and the On-Peak time period is 12 noon to 3 p.m. and 6pm to 7pm, during the Super Peak Summer months Monday through Friday excluding the holidays listed below. The On-Peak time period during Summer and Winter months for this rate schedule is 12 noon to 7 p.m. Monday through Friday excluding the holidays listed below. All hours not included in the Super-Peak or On-Peak time periods shall be Off-Peak hours for all seasons.

The following holidays are Off-Peak: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25). When any holiday listed above falls on a Saturday, the preceding Friday will be recognized as an off-peak period. When any holiday listed above falls on a Sunday, the following Monday will be recognized as an off-peak period. Mountain Standard Time shall be used in the application of this rate schedule.

RATE SCHEDULE ET-SP
RESIDENTIAL SERVICE TIME-OF-USE
TIME ADVANTAGE SUPER PEAK 7PM-NOON

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE CPP-GS
CRITICAL PEAK PRICING – GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

The Rate Schedule CPP-GS is available to retail Standard Offer customers served on Rate Schedules E-32 M, E-32 L, E-32TOU M, E-32TOU L, E-34, E-35, and E-221. The eligible customer must demonstrate the ability to reduce usage during Critical Events by a minimum of 200 kW and submit a load reduction plan, which must be approved by the Company prior to participation. The eligible customer must also have interval metering. All provisions of the Customer's otherwise applicable rate schedule will apply in addition to the charges in Schedule CPP-GS. Partcipation is limited to the first 100 customers for a period of two years from the initial availability. The Company may expand eligibility during this two-year period, at its discretion, upon notification to the Commisison.

RATES

A. Critical Peak Price	$0.40000	per kWh
Critical Peak Price applies to kWh usage during a CPP Event.		
B. Energy Discount		
Rate Schedule E-32 M (401-999 kW)	$(0.014892)	per kWh
Rate Schedule E-32 L (1000+ kW)	$(0.014438)	per kWh
Rate Schedule E-32 TOU M (401-999 kW)	$(0.014892)	per kWh
Rate Schedule E-32 TOU L (1000+ kW)	$(0.014438)	per kWh
Rate Schedule E-34	$(0.014350)	per kWh
Rate Schedule E-35	$(0.012470)	per kWh
Rate Schedule E-221	$(0.011755)	per kWh
Energy Discount applies to Customer's total monthly kWh.		

CONDITIONS

A. CPP Events: CPP Events may be invoked by the Company for the period 2 p.m. to 7 p.m., weekdays (Monday through Friday) during June through September. Holidays are excluded, which include Independence Day (July 4th) and Labor Day (first Monday in September). A CPP Event can be triggered by severe weather, high load, high wholesale prices, or a major generation or transmission outage, as determined by the Company.

B. Number and Duration of CPP Events: The Company may invoke a maximum of 18 CPP Events per calendar year, for 5 hours per event and 90 hours per year.

C. CPP Event Notification/Communication: Customers would be notified of a CPP Event in advance by 4:00 PM the day prior through a phone message and e-mail. Receipt of such notice is the responsibility of the participating customer.

D. CPP Event Cancellation: Once a CPP event alert has been initiated, there are no conditions that would warrant the critical event to be cancelled.