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AZ CORP COMMISSION
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Transcript Exhibit(s)

Docket #(s): E-01345A-05-0816

E-01345A-05-0826

E-01345A-05-0827

Arizona Corporation Commission
DOCKETED

DEC 29 2006

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Exhibit #: APS22 - APS44

(Part 5 of 9)

EXHIBIT
APS-22
admitted

ARIZONA PUBLIC SERVICE COMPANY
Total Company
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
(Dollars in Thousands)

Line No.	Description	Total Company: Actual For The Test Year Ended 9/30/05 (a)	Proforma Adjustments (b)	Test Year Results After Proforma Adjustments (c)	Line No.
1.	Electric operating revenues	$ 3,371,546	$ 138,174	$ 3,509,720	1.
	Operating expenses:				
2.	Purchased power and fuel	1,822,565	351,718	2,174,283	2.
3.	Operations and maintenance	573,962	110,247	684,209	3.
4.	Depreciation and amortization	318,961	25,729	344,690	4.
5.	Income taxes	153,962	(144,010)	9,952	5.
6.	Other taxes	124,972	16,867	141,839	6.
7.	Total	2,994,422	360,551	3,354,973	7.
8.	Operating income	377,124	(222,377)	154,747	8.
	Other income (deductions):				
9.	Income taxes	56,698	-	56,698	9.
10.	Allowance for equity funds used during construction	10,433	-	10,433	10.
11.	Regulatory disallowance	(143,217)	-	(143,217)	11.
12.	Other income	26,019	-	26,019	12.
13.	Other expense	(15,176)	-	(15,176)	13.
14.	Total	(65,243)	-	(65,243)	14.
15.	Income before interest deductions	311,881	(222,377)	89,504	15.
	Interest deductions:				
16.	Interest on long-term debt	141,301	-	141,301	16.
17.	Interest on short-term borrowings	6,285	-	6,285	17.
18.	Debt discount, premium and expense	4,344	-	4,344	18.
19.	Capitalized interest	(7,257)	-	(7,257)	19.
20.	Total	144,673	-	144,673	20.
21.	Net income	$ 167,208	$ (222,377)	$ (55,169)	21.

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-1

ARIZONA PUBLIC SERVICE COMPANY
Total Company
10K vs. FERC Revenues and Purchased Power/Fuel
Test Year 12 Months Ended 9/30/05

CNF_WP4

(Dollars in Thousands)

Line No.	Description	Acct	Total Company: APS 10Q For The Test Year Ended 9/30/05 (a)	FERC Form 1 For The Test Year Ended 9/30/05 (b) Revenue	FERC Form 1 For The Test Year Ended 9/30/05 (b) PP & Fuel	Line No.
	Electric operating revenues:					
	Native Load Revenue:					
1.	Forfeited Discounts	4500	$ 8,187	$ 8,187	$ -	1.
2.	Misc Service Revenues	4510	9,722	9,722		2.
3.	Rent from Electric Prop	4540	5,612	5,612		3.
4.	Other Electric Revenues	4560	34,213	34,213		4.
5.	Intercompany Transmission Revenue	4563	129,704	129,704		5.
6.	Intercompany Transmission Revenue	4564	(123,428)	(123,428)		6.
7.	Residential Sales	4400	1,062,510	1,062,510		7.
8.	Commercial & Industrial Sales	4420	1,012,560	1,012,560		8.
9.	Public Street & Hwy Lighting	4440	12,828	12,828		9.
10.	Other Sales to Public Auth	4450	132	132		10.
11.	Sales for Resale	4470	20,794	20,794		11.
12.	Provision for Rate Refunds	4491	(3,958)	(3,958)		12.
	Marketing and Trading Revenue:					
13.	System Sales Broker Fees	5574	(100)		100	13.
14.	Purchased Power Net	5552	(815,224)		815,224	14.
15.	Power & Fuel	5651	(763)		763	15.
16.	Marketing and Trading Revenue	4562	(275)	(275)		16.
17.	Trading MTM Revenue	4213	(13,490)		13,490	17.
18.	MTM Nontrading Revenue	4215	1,470		(1,470)	18.
19.	Marketing & Trading Revenue	4472	849,133	849,133		19.
	System Sales Revenue:					
20.	Purchased Power APS	4214	(763)		763	20.
21.	System Sales Revenue	5553	(83,136)		83,136	21.
22.	System Sales Revenue	4561	(691)	(691)		22.
23.	System Sales Revenue	4474	159,409	159,409		23.
24.	Total Electric Operating Revenues - APS		2,264,246			24.
	Purchased Power and Fuel Costs:					
	Native Load Purchased Power:					
25.	Purchased Power	5550	120,073		120,073	25.
26.	Other Transmission Expenses	5571	295		295	26.
27.	Trans of Electricity by Others	5650	13,628		13,628	27.
	Native Load Fuel:					
28.	Steam Power Fuel	5010	226,892		226,892	28.
29.	Allowances	5090			-	29.
30.	Nuclear Fuel	5180	41,762		41,762	30.
31.	Other Prod	5470	162,151		162,151	31.
	Retail Hedge Purchased Power & Fuel:					
32.	Retail Hedge Purchased Power & Fuel	5554	189,459		189,459	32.
33.	Retail Hedge Purchased Power & Fuel	4473	(195,294)	195,294		33.
34.	Marketing and Trading Purchased Power	5556	27,511		27,511	34.
35.	System Sales Fuel	5472	50,448		50,448	35.
	System Sales Purchased Power:					
36.	Marketing and Trading Broker Fees	5573	31		31	36.
37.	System Sales Purchased Power	5555	78,289		78,289	37.
38.	Total Purchased Power and Fuel Costs - APS		715,265			38.
39.	Total FERC Revenue & Purchased Power & Fuel			3,371,546	1,822,565	39.
40.	Operating Revenue Less Purchased Power and Fuel Costs		$ 1,548,981		$ 1,548,981	40.

C-1(3)

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(1) SFR Sch. C-2 Total as filed on Jan. 31, 2006 Income Statement Adjustments		(2) REBUTTAL Tax Consulting Fees		(3) REBUTTAL Unregulated APS Marketing and Trading Activity	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Electric Operating Revenues	$ 138,174	$ 137,135	$ -	$ -	$ (849,248)	$ (835,567)
2.	Purchased Power and Fuel Costs	351,718	350,695	-	-	(855,618)	(841,847)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(213,544)	(213,560)	-	-	6,370	6,280
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	65,716	63,234	(2,778)	(2,746)	(6,618)	(6,511)
5.	Maintenance	17,131	16,756	-	-	-	-
6.	Subtotal	82,847	79,990	(2,778)	(2,746)	(6,618)	(6,511)
7.	Depreciation and Amortization	25,806	23,504	-	-	-	-
8.	Amortization of Gain	(77)	(71)	-	-	-	-
9.	Administrative and General	27,400	24,958	-	-	(2,161)	(2,126)
10.	Other Taxes	16,867	16,719	-	-	-	-
11.	Total	152,843	145,100	(2,778)	(2,746)	(8,779)	(8,637)
12.	Operating Income Before Income Tax	(366,387)	(358,660)	2,778	2,746	15,149	14,917
13.	Interest Expense	(5,669)	(4,470)	-	-	-	-
14.	Taxable Income	(360,718)	(354,190)	2,778	2,746	15,149	14,917
15.	Current Income Tax Rate - 39.05%	(144,010)	(140,396)	1,085	1,072	5,916	5,825
16.	Operating Income (line 12 - line 15)	$ (222,377)	$ (218,264)	$ 1,693	$ 1,674	$ 9,233	$ 9,092
	WITNESS:			FROGGATT		FROGGATT	

(1) Total Income Statement Adjustments from APS' Direct Testimony filed on Jan. 31, 2006. Please see SFR Schedule C-2, page 11, Columns (KKK) and (LLL).

(2) Additional adjustment to operating expense to remove out-of-period and non-recurring tax consultant fees.

(3) Additional operating income pro forma to remove APS unregulated marketing and trading activities from operating expense.

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Income Statement
Test Year 12 Months Ended 9/30/2005

(Dollars in Thousands)

		ACC Jurisdiction		
Line No.	Description	SFR Schedule C-1 as Filed on 1/31/06	Rebuttal Adjustments to C-1	Rebuttal Adjusted C-1
		(a)	(b)	(c)
1	Electric operating revenues	$ 3,440,590	$ (823,174)	$ 2,617,416
2	Purchased power and fuel costs	2,129,741	(797,409)	1,332,332
3	Operating revenues less purchased power and fuel costs	1,310,849	(25,765)	1,285,084
4	Other operating expenses:			
5	Operation and maintenance	766,212	(20,209)	746,003
6	Depreciation and amortization	306,988	(259)	306,729
7	Income taxes	395	(7,116)	(6,721)
8	Payroll and Other taxes	121,350	(1,688)	119,662
9	Total	1,194,945	(29,272)	1,165,673
10	Operating income	$ 115,904	$ 3,507	$ 119,411

DIRECT TESTIMONY OF STEVEN M. FETTER

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

January 31, 2006

EXHIBIT
APS 23
admitted

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TESTIMONY OF STEVEN M. FETTER
PRESIDENT, REGULATION UnFETTERED
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816
BEFORE THE
ARIZONA CORPORATION COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven M. Fetter, and my business address is 1489 West Warm Springs Road, Suite 110, Henderson, NV 89014.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President of REGULATION UnFETTERED, an energy advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission ("Michigan PSC" or "Michigan Commission").

Q. PLEASE BRIEFLY DESCRIBE YOUR ROLE AS PRESIDENT OF REGULATION UnFETTERED.

A. I formed an energy advisory firm to use my financial, regulatory, legislative and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include electric and gas utilities, state public utility commissions

1 and consumer advocates, a non-utility energy supplier, international
2 financial services and consulting firms, and investors.
3
4 **Q. PLEASE BRIEFLY DESCRIBE FITCH'S BUSINESS DURING YOUR**
5 **TENURE THERE.**
6 A. Fitch is the third largest full service credit rating agency in the United
7 States – after its two major competitors, Standard & Poor's ("S&P") and
8 Moody's Investors Service ("Moody's") -- and the largest European rating
9 agency. It is one of four Nationally Recognized Statistical Rating
10 Organizations recognized by the U.S. Securities and Exchange
11 Commission. It is also recognized by the U.S. Department of Labor, state
12 bank and thrift regulators, and the National Association of Insurance
13 Commissioners. Fitch performs credit ratings of corporate obligations,
14 asset-backed transactions, and government and municipal debt. While
15 fees are paid by bond issuer clients, Fitch views its true clients to be bond
16 investors. Accordingly, bond ratings represent Fitch's independent
17 judgment based upon financial data provided by the bond issuer as well
18 as additional quantitative and qualitative information gathered from third-
19 party sources.
20
21 **Q. WHAT WAS YOUR ROLE DURING YOUR EMPLOYMENT WITH**
22 **FITCH?**

1 A. I was Group Head and Managing Director of the Global Power Group
2 within Fitch. In that role, I served as group manager of the combined 18-
3 person New York and Chicago utility team and was also responsible for
4 interpreting the impact of regulatory and legislative developments on utility
5 credit ratings. In April 2002, I left Fitch to start REGULATION
6 UnFETTERED, an energy advisory firm.
7
8 **Q. HOW LONG WERE YOU EMPLOYED BY FITCH?**
9 A. I was employed by Fitch from October 1993 until April 2002. In addition,
10 Fitch retained me as a consultant for a period of approximately six months
11 shortly after I resigned.
12
13 **Q. HOW DOES YOUR EXPERIENCE AT FITCH RELATE TO YOUR**
14 **TESTIMONY IN THIS PROCEEDING?**
15 A. At the time I was hired, Fitch intended to supplement the traditional
16 quantitative analysis that went into the firm's utility credit ratings with a
17 new emphasis on qualitative analysis. Fitch sought my assistance on the
18 regulatory, legislative and political credit rating factors that would
19 accompany U.S. movement toward a less regulated, more competitive
20 utility environment, both on the electric side as well as within the natural
21 gas industry. I guided the Global Power Group in incorporating these
22 issues into individual utility credit profiles.
23

1 My experience with Fitch has given me solid insight into the importance of
2 a regulator's role in both setting rates and also determining appropriate
3 terms and conditions of service. These are the factors that enter into the
4 process of utility credit analysis and formulation of individual company
5 credit ratings. It goes without saying that a company's credit ratings have
6 a significant impact as to whether a utility will be able to raise capital on a
7 timely basis and upon favorable terms.
8
9 **Q. PLEASE DESCRIBE YOUR SERVICE ON THE MICHIGAN PUBLIC**
10 **SERVICE COMMISSION.**
11 A. I was appointed as a Commissioner to the three-member Michigan PSC in
12 October 1987 by Democratic Governor James Blanchard. In January
13 1991, I was promoted to Chairman by incoming Republican Governor
14 John Engler, who reappointed me in July 1993. During my tenure as
15 Chairman, the Michigan PSC eliminated the agency's case backlog for the
16 first time in 23 years.
17
18 **Q. WAS THERE ANY ASPECT OF YOUR EXPERIENCE AT THE**
19 **MICHIGAN PSC THAT PARTICULARLY RELATES TO YOUR**
20 **TESTIMONY IN THIS PROCEEDING?**
21 A. Yes. During my six years at the Michigan PSC, my colleagues and I
22 sought to effectuate policies that would encourage regulated utilities to
23 provide customers with reliable electric and natural gas service in a cost-

effective manner. We also sought to ensure that the financial health of the state's utilities would remain sufficient for them to be able to provide reliable service to all consumers, and also that investors would maintain their interest in providing necessary funding on a timely basis upon reasonable terms.

Achieving these goals requires regulators to successfully strike a difficult balancing of interests. Investors provide financing to a utility so that company management can construct and maintain infrastructure adequate to ensure that customers will receive reliable service. In return, regulators must take timely action to provide an appropriate capital markets-based return to investors for company expenditures that are prudently made. A failure to carry out this regulatory responsibility in a timely manner will ultimately be detrimental to both investors and customers as investors will choose to take their funds elsewhere. Similarly, a regulatory or legislative determination that a utility should financially support certain public policy mandates without receiving timely recovery for prudent expenditures made in those efforts would undoubtedly lead investors to look to other jurisdictions where they believe their investments will be treated more fairly.

I believe that all of the circumstances I have describe above are relevant to the issues before the Arizona Corporation Commission ("Commission")

in this proceeding, and I will further elaborate upon these points within the remainder of my testimony.

Q. PLEASE DESCRIBE YOUR OTHER PRIOR PROFESSIONAL EXPERIENCE RELATED TO THE UTILITY INDUSTRY.

A. During my time on the Michigan PSC, I served as Chairman of the Board of Directors of the National Regulatory Research Institute ("NRRI") at Ohio State University, the regulatory research arm of the 50 state and District of Columbia public utility commissions. In 2003 I was appointed by the President of the National Association of Regulatory Utility Commissioners ("NARUC") to serve as a public member of the NRRI Board – the 20-member board includes ten state public utility commissioners. I was reappointed to the NRRI Board for a three-year term in June 2005. I also have served on the Keystone Center Energy Board (a nonprofit public policy board that brings together diverse stakeholders related to the energy industry as well as appointed and elected federal and state policymakers to discuss challenges facing the sector), after having participated in the Keystone Center Dialogues on Financial Markets and Energy Trading and on Regional Transmission Organizations. In February 2002, I was appointed to the Board of Directors of CH Energy Group, Inc. ("CHG"), the parent company of Central Hudson Gas & Electric in Poughkeepsie, New York. I currently serve as chairman of the CHG Audit Committee.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE REGULATORY AND LEGISLATIVE BODIES?

A. Since 1990, I have on numerous occasions testified before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, and various state legislative and regulatory bodies on the subjects of credit risk within the utility sector, electric and natural gas utility restructuring, utility securitization bonds, and nuclear energy. During 2004, I sponsored testimony on behalf of Arizona Public Service Co. ("APS" or "Company") before the Commission in APS' general rate case, Docket No. E-01345A-03-0437. I also sponsored testimony on behalf of APS during the proceeding that followed to consider the appropriateness of the settlement agreement that was filed within that rate case. Finally, I have also filed testimony before this Commission in 2004 on behalf of Southwest Gas Corporation in Docket No. G-01551A-04-0876.

My full educational and professional background is attached in Appendix A.

II. SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. In this testimony, I offer my opinion, based upon my prior experience as head of the utility ratings practice at a major credit rating agency, chairman of a state public utility commission, and consultant to utilities, commissions and consumer advocates, as to what comprises fair and economically prudent regulation within today's electric utility industry. As part of that analysis, I will offer a brief discussion of the mechanics of the utility rate-setting process and how those steps help to ensure a regulated utility's financial viability and ability to provide service on a going-forward basis.

I further note my belief that the recent instability in the financial markets has created challenges for utility managements and regulators to an extent that has never existed in the past. Utilities possess an ongoing need for substantial amounts of funds for capital investment, both for infrastructure enhancement as well as maintenance of continuing reliability. Following the recent period of unprecedented volatility in the utility equity and debt markets, I believe that utilities operating within today's more stressful environment and their regulatory authorities should strive to minimize the regulatory uncertainties that could affect a utility's

1 financial profile, its credit ratings, and thus its access to capital on
2 favorable terms. Of course, a utility's ability to maintain its financial
3 strength also helps customers in that it allows the company's cost of
4 capital – that gets factored into rates -- to remain at reasonable levels.
5
6 In my testimony, I highlight recent statements from S&P as to what its
7 analysts look for to conclude that a constructive regulatory environment
8 exists within a particular jurisdiction: "...consistency and predictability, as
9 well as efficiency and timeliness," and limits on "uncertainty in the
10 recovery of a utility's investment [and] rate-case lag that may prove
11 detrimental if a utility needs rate relief."[1]
12
13 Moreover, for a utility like APS, whose customer growth means that it has
14 to rely upon a substantial amount of purchased power and Company-
15 owned natural gas generation, a power supply adjustor ("PSA") to reflect
16 actual costs is a key factor in the eyes of the financial community. While
17 Wall Street viewed the introduction of a PSA for APS last year as a
18 positive event, the way in which the PSA has operated has not been
19 consistent with the theoretical underpinning of other PSA-like mechanisms
20 that are being utilized across the U.S. nor, for that matter, as the PSA in
21 Arizona was intended to operate when it was negotiated by the parties to
22 APS' last rate case. I believe it is incumbent upon the Commission to
23 build upon its introduction of the concept and implement a PSA that bears

[1] S&P Research: "U.S. Utility Regulation Returns to Center Stage," April 14, 2005.

characteristics more consistent with the mainstream of regulatory practice within the U.S. On this point, I discuss the workings of the existing PSA that has resulted in large unrecovered power supply cost balances for APS and how delays in dealing with these deferred amounts and uncertainty with regard to ultimate recovery has led S&P to downgrade APS' corporate credit rating to the lowest investment-grade level.

In view of the difficult circumstances confronting APS, I encourage the Commission to be aggressive in dealing with these issues. Current industry circumstances require more than just the passive regulatory model that existed for the better part of a century, under which investors were only interested in the results of rate cases, with the issuance of rate case decisions occurring relatively infrequently. Rather, as I explain, a proactive regulatory attitude best serves the interests of all stakeholders affected by today's evolving utility industry.

By acting promptly to provide regulatory support for fair cost recovery in a way that ensures the financial integrity of the utilities operating within their jurisdictions, regulators can benefit customers of those utilities with efficient and reliable service while respecting the interests of investors who are continually called upon to provide the funding I describe above. In addition, state and local economic development agencies often use the

availability of reliable energy supply at reasonable cost as a selling point in their efforts to attract new businesses to their areas.

III. UTILITY RATE-SETTING PROCESS

Q. COULD YOU PROVIDE A BRIEF EXPLANATION OF THE UTILITY RATE-SETTING PROCESS?

A. Yes I can. The intent of the rate-setting process for a regulated utility is to serve as a surrogate for the competitive market that non-regulated companies of any type operate within on a daily basis. The goals of rate-setting should be to ensure fair treatment of both the customers and the shareholders and bondholders of a regulated utility by providing prompt cost recovery of the prudent expenditures necessary for the provision of stable and reliable service. In short, the process begins with a regulatory determination of a revenue requirement, an estimate of the total costs (including O & M and return on rate base) a utility will incur in providing service in the future, and a determination as to the process through which those expenditures will be recovered.

Q. CAN YOU EXPLAIN HOW REGULATORS CONTINUE THE PROCESS OF SETTING A UTILITY'S REVENUE REQUIREMENT BY DETERMINING A RATE OF RETURN (INCLUDING A RETURN ON EQUITY) FOR A COMPANY?

A. As I mentioned, regulation serves as a surrogate for the competitive marketplace. The setting of a utility rate of return is based upon a regulatory calculation of the investment return necessary to attract investors to provide funds to the utility to carry out its service obligations to the public. The calculation incorporates two percentages: the amount of interest that bondholders will require before they will lend money to the utility and the return on equity that equity investors will demand in order to become part owners (through the holding of shares of stock) of the company. A weighted average of these two percentages results in the overall cost of capital, the level at which a utility will be able to attract the capital it needs in order to provide an appropriate level of reliable service to customers. The overall revenue requirement, whether based on original cost, "fair value," or replacement cost, must at a minimum include a sufficient return to recover a utility's cost of capital.

While the expense side of the revenue requirement calculation is relatively straightforward, the determination of the appropriate rate of return for a utility is a more complex and somewhat academic exercise, owing to the existence of two seminal U.S. Supreme Court decisions dating back more than 50 years ago: *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*[2] and *Federal Power Commission v. Hope Natural Gas Co.*[3]. The decisions in these two cases require

[2] 262 U.S. 679 (1923).
[3] 320 U.S. 591 (1944).

regulators to set a utility's rate of return at a level sufficient to attract capital on reasonable terms, to allow the utility to maintain its financial integrity, and to provide the utility with the opportunity to achieve earnings commensurate with the risks that it faces. Such determination is made on a case-by-case basis, depending upon the particular circumstances that an individual utility operates under. Although these decisions were framed in legal terms many years ago, they also reflected a prescience by the courts with regard to the economic realities of the manner in which the capital markets have evolved to the current time.

Q. HAS THE VOLATILITY THAT HAS CHARACTERIZED THE UTILITY SECTOR DURING THE PAST FIVE YEARS HAD AN IMPACT UPON THE RISK ASSESSMENT THAT GOES INTO DETERMINATION OF A FAIR RATE OF RETURN?

A. Yes, without a doubt, and it has affected both non-regulated and regulated utility operations. The two most jarring events to utility investors during the past several years – the California crisis and the Enron collapse – are good examples of the types of risk that were totally unforeseen at the start of the utility restructuring movement.

In California – where a state legislative/regulatory framework called for capped retail rates, notwithstanding exploding wholesale costs – reluctance on the part of state regulators (and legislators) to take proactive

steps necessary to remedy the dire situation resulted in the bankruptcy and near-bankruptcy of California's two largest *regulated* utilities, Pacific Gas & Electric Co. ("PG&E") and Southern California Edison Co. ("SCE"). The crisis had little to do with the unregulated affiliates of these two companies. The electric market problems in California also crossed state lines and brought financial harm to "innocent" regulated investor-owned utilities in Nevada and self-regulated public power utilities in the Pacific Northwest.

Conversely, the Enron collapse related almost solely to fraudulent behavior with regard to unregulated activities. What these two situations tell me is that the turmoil within the utility sector is not appropriately described as a dichotomy between higher risk unregulated activities and lower risk regulated activities. Rather, it is a succession of individual utility setbacks that has cut across the entire sector, affecting both regulated and unregulated companies.

Q. WHAT DO THOSE EXPERIENCES MEAN FOR INVESTORS?

A. Investors can choose to invest within the utility sector or they can invest in other sectors such as technology, financial services, or international (including emerging) markets. If they choose to invest in utilities, they must take the sector as they find it now – including its recent history of injurious regulatory policies and missteps. That said, risk profiles across

the industry are diverse, and an investor can choose to determine its risk tolerance and seek out a competitive energy company, regulated utility, or some combination of the two that falls within both its risk and return parameters. I emphasize, however, that an investor's decision to invest in a company with significant involvement in regulated utility services, like APS, does not shield that investor against all industry risk – as was so clearly seen in Nevada.

Integrated utilities cannot be viewed as they were several years ago. While a certain degree of industry risk resided in the minds of investors with regard to PG&E and SCE five years ago, the disasters that were to befall those two companies were inconceivable in the minds of Wall Street analysts and investors. In other words, what eventually occurred to these companies was not even within the realm of possibility based upon their risk profiles.

Unfortunately, what this means for current utility investors is that their risk radar is set at a much lower tolerance level today. Notwithstanding gradations among individual utilities, the entire sector bears the brunt of this more negative perception. Indeed, general concerns about a more volatile industry were reinforced by the August 14, 2003 blackout and then virtually overwhelmed by the damage wrought by Hurricanes Katrina and Rita, with the accompanying bankruptcy filing by Entergy New Orleans. It

has also become clear that, at least for the foreseeable future, there will be an ongoing need for substantial investment in transmission infrastructure for all utilities, as well as distribution system enhancement for regulated utilities in fast-growing regions of the country, such as APS.

Q. IN VIEW OF THESE UNPRECEDENTED EVENTS DURING THE PAST FIVE YEARS, DO THE ACTIONS OF UTILITY REGULATORS TODAY DRAW EVEN MORE ATTENTION FROM THE FINANCIAL COMMUNITY?

A. Yes, without a doubt. Regulation has always garnered the attention of Wall Street, but years ago, seemingly only during the days leading up to a commission's rate case decision. This began to change around the time that Fitch hired me in 1993 to serve in the role of regulatory analyst and assess regulatory and political factors that could impact upon a utility's financial strength. When California announced its ultimately ill-fated restructuring plan in 1994, the entire financial community, especially Fitch and its rating agency competitors S&P and Moody's, took much greater notice of regulators and how they carried out their responsibilities, not only with regard to rate-setting, but even more importantly the manner in which they undertook to change the way the entire utility industry had operated for over 100 years.

Under most restructuring plans, utilities have been directed to foster the

development of competitive markets, materially scale down their operations for certain functions (often including divestiture of generation), while at the same time retaining responsibility to produce or procure electricity for their core customers.

This situation thus affects utility investment decisions because, before major energy investors will be willing to put forward substantial sums of money, they will want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a rapidly evolving industry and that their decision-making will be fair and will have a significant degree of predictability.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by the commissions. If a regulatory body were to expect or encourage a company to make investments based upon an expectation of the opportunity to earn a reasonable return, and then did not apply regulatory principles in a manner consistent with such expectations, investor interest in providing funds to such utility would decline, debt ratings would likely suffer, and the utility's cost of capital would increase.

S&P highlighted the continuing importance of regulation to the financial community in two recent reports. In a report entitled "New York

Regulators' Consistency Supports Electric Utility Credit Quality," S&P offered general thoughts on the importance of regulation that apply within but also far beyond the borders of New York State:

> "Regulation defines the environment in which a utility operates and greatly influences a company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy as a result of supportive regulation. Conversely, an unpredictable or antagonistic regulatory environment can undermine the financial position of utilities that are operationally very strong.
>
> To be viewed positively, regulatory treatment should be timely and allow consistent performance over time, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory policies..."[4]

Earlier, S&P had discussed how changing circumstances within the utility industry have elevated the importance of regulatory policies:

> "In recent years, [S&P's] emphasis on the decisions by state commissions has been less pronounced simply because so many jurisdictions have been working through multiyear restructuring transition periods. During this time, rates were frequently frozen, and companies and customers have been adjusting (albeit with limited success) to the opportunity that customers have to choose alternate power suppliers.
>
> But the confluence of the approaching end of these transition periods and the growing need in certain regions of the country for significant resource additions is quickly returning the regulatory arena to center stage. In assessing the regulatory environment in which a utility operates, [S&P's] analysis is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag that may prove detrimental if a utility needs rate relief."[5]

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[4] S&P Research: "New York Regulators' Consistency Supports Electric Utility Credit Quality," August 15, 2005.

[5] S&P Research: "U.S. Utility Regulation Returns to Center Stage," April 14, 2005.

Q. IN VIEW OF THE IMPORTANCE THAT REGULATION HOLDS FOR INVESTORS, DID THE COMMISSION'S APPROVAL OF THE APS RATE CASE SETTLEMENT LAST YEAR RESOLVE ALL RISK CONCERNS RELATING TO APS IN THE MINDS OF INVESTORS?

No it did not. At the time, S&P explained that APS still faced near-term challenges and that they are largely regulatory:

> "Timely recovery of costs incurred in the rate base will remain challenges for the utility...Because these rates are based on a December 2002 test year, the utility will need to soon file a new rate case to reflect its significant capital expenditures and to keep current on its generation costs that are gradually becoming more concentrated in natural gas. While the fuel and purchased power adjuster is expected to provide some rate relief to the utility, the adjuster is capped at a level that will likely need to be revisited well before its expiration in five years. And, because load growth in APS' service territory is projected to grow between 4%-6% per year over the next five years, APS will still need an additional 1,200 MW by the summer of 2007 to fill the gap between power supply and demand."[6]

S&P concluded that APS' ratings outlook was Stable, but that:

> "The failure of PWCC or APS to meet expected financial results in 2005 and 2006, particularly in light of the weakening in consolidated and utility credit metrics in 2004, could lead to a downward revision of the outlook or a ratings change. Downward pressure on the ratings will occur if APS incurs significant power or fuel cost deferrals in excess of the fuel and purchased power adjuster's limitations. Any positive rating action is unlikely in the near-term given the financial metrics and the longer term risks that the terms of the PSA present."

Q. S&P REFERS TO LIMITATIONS THAT CURRENTLY APPLY TO THE PSA. COULD YOU DISCUSS THAT ASPECT OF THE PSA?

[6] S&P Research Summary: "Arizona Public Service Co.," May 24, 2005.

A. Yes I can. First, the PSA as structured by the Commission last year contains a four-tenths of a cent per kilowatt-hour cap on any fuel or purchased power expense recovery by APS through the annual adjustor. Second, there is a "lifetime" limit of this four-tenths of a cent per kilowatt-hour cap. Third, there is a maximum recovery amount of $776 million established. Finally, there is no automatic approval mechanism for the company's annual application under this PSA. These types of items set the structure of the existing PSA apart from other such mechanisms utilized across the U.S.

Q. COULD YOU DISCUSS THE SIGNIFICANCE OF THE $776 MILLION CAP?

A. Yes. Per Commission Decision 67744, "putting a 'cap' on recovery of these costs will help insure that APS will file a rate application when necessary". If the cap is removed before it is reached, it is not an issue. However, if the cap remains, it is a significant issue.

Q. COULD YOU EXPLAIN?

A. Yes. Since the PSA is structured to reimburse APS *only for a portion of its prudently-incurred* fuel and purchased power expenses, I find such a cap to be outside the norm in a way that could defeat the intended purpose of such an adjustment mechanism. Also, by dampening down the "true" price of power by maintaining a cap that bears no relation to the prudency

of APS' actions, the PSA ends up sending improper price signals during a time when a wide range of industry stakeholders are seeking to tie actual prices to encouragement for substantially greater progress with regard to conservation, energy efficiency, and other demand side management initiatives.

Q. WHAT IMPACT COULD THAT CAP HAVE ON FUEL EXPENDITURES THAT ARE PRUDENTLY INCURRED BY APS IN ORDER TO PROVIDE RELIABLE SERVICE TO ITS NATIVE LOAD CUSTOMERS?

A. Such a cap could prevent APS from achieving recovery of its prudent fuel and purchased power expenditures as intended by the PSA (in the absence of the unusual cap). That result would certainly be viewed as a negative outcome by the financial community – one that would not be favorably received by the equity and credit rating analysts that follow APS' regulatory situation and either consider credit rating actions that affect debt investors or stock recommendations that impact equity investors. In fact, the Residential Utility Consumer Office ("RUCO") has stated that such denial of recovery for prudent fuel and purchased power expenditures was not intended when the PSA was structured and agreed to by the 20+ parties in APS' last rate case:

> "...the Commission modified certain aspects of the PSA from those proposed by the parties to the Settlement Agreement. However, those modifications did not change RUCO's view of the PSA, and any approved surcharges, as a device through which APS would recover ninety percent of its prudent costs of fuel and purchased

power...none of the Commission's revisions changed the underlying premise that the costs would be recoverable."[7]

To the extent that the PSA as currently structured does **not** provide APS with recovery for its prudent fuel and purchased power expenditures, it would have to be changed in order to be consistent with the vast majority of such mechanisms around the country.

Q. HAVE GROWING POWER COST DEFERRALS INCREASED THE LEVEL OF CONCERN AMONG THE RATING AGENCIES?

A. Yes they have. In October 2005, S&P expressed increasing concern about APS' growing amount of deferrals, related both to day-to-day power supply for core customers, as well as replacement power related to a nuclear outage earlier this year:

> "...it is clear that timely near-term [power] cost collection will be the key driver of credit quality. Standard & Poor's is becoming increasingly concerned with the utility's ability to achieve this. A relatively weak power supply adjustment mechanism, in combination with rapidly escalating and volatile gas prices, as well as the potential for a protracted surcharge proceeding, could cause deterioration in financial performance which, year to date, has been sub par for the rating."[8]

On December 21, 2005, S&P acted on its earlier warnings and lowered its corporate credit rating for APS to "BBB-" from "BBB". S&P concluded that "Any adverse regulatory development or continued delays in resolving the pending surcharge request could result in a downward revision of the

[7] Letter from RUCO to Commissioner Kristin K. Mayes, August 19, 2005.
[8] S&P Research: Arizona Public Service Co., October 4, 2005.

outlook or an adverse rating action."[9] This downgrade to the lowest investment-grade level of "BBB-" is a very negative financial event.

Q. WHAT ARE SOME OF THE CONSEQUENCES IF APS' CREDIT RATING WERE TO FALL BELOW INVESTMENT-GRADE QUALITY?

A. There would be a marked change in the investor profile for the Company. Major utility investors such as insurance companies and pension funds operate under legal restrictions that severely limit their ability to invest in below investment-grade debt instruments, or "junk bonds." Mutual funds could also be affected based upon what a particular fund has communicated to investors as to its investment profile. Moreover, a utility with a "junk bond" rating is likely to have to post bond or put up cash as collateral in various contracts (such as for power supply) or to meet certain regulatory commitments. This, of course, would come at a time when access to APS' existing credit facilities likely would be limited by the financial institutions previously providing the assistance. Finally, a utility with below investment-grade status is severely limited in its ability to access the commercial paper (short-term debt) market, if it can access it at all. Commercial paper is a key source of funding for utilities (including APS), many of which have revenues that vary substantially depending upon the time of year, and loss of access to that market can severely impair financial liquidity.

[9] S&P Research Update: "Pinnacle West Capital's, Arizona Public Service's Ratings Lowered To 'BBB-'; Outlook Stable," December 21, 2005.

Q. IS IT EASY FOR A COMPANY THAT HAS BEEN DOWNGRADED TO REGAIN ITS PRIOR CREDIT RATING?

A. No, not at all. It is important to emphasize that within the more volatile investment climate, it is far easier for a utility's ratings to slip down due to a financial "ding" than for that same utility to regain its earlier status once the deficiency has been remedied. For that reason, I do not believe that a continuation in the weakening of APS' credit profile now could, if the Commission changed its mind, be easily remedied in the Company's next proceeding. My advice to utility companies, investors and regulators alike is that nothing should be taken for granted in the current investing environment.

Q. ON THE OTHER SIDE OF THE COIN, CAN YOU OFFER EXAMPLES OF RECENT REGULATORY ACTIONS THAT HAVE IMPACTED IN A POSITIVE WAY HOW THE FINANCIAL COMMUNITY VIEWS REGULATION IN A PARTICULAR JURISDICTION?

A. Yes I can. First I would like to discuss recent activity in Missouri with which I was involved as an advisor assisting Great Plains Energy and its regulated utility Kansas City Power & Light Co. ("KCPL") in their interaction with state regulators.

Q. WHAT WERE THE CIRCUMSTANCES SURROUNDING KCPL'S

1 **INVOLVEMENT WITH MISSOURI REGULATORS?**

2 A. KCPL was facing a situation where it saw the need to expend a
3 substantial amount of capital (approximately $1.3 billion) over a five-year
4 period to assure adequate electricity supply for its core customer base. At
5 the same time, with its credit ratings at the "BBB" level, the company did
6 not want to stress its credit profile in a way that could lower them to low-
7 "BBB" status or even down into below-investment grade status.
8
9 To achieve its goal of assuring ongoing reliable service to its regulated
10 customers in a financially-prudent manner, KCPL interacted with Missouri
11 regulatory staff and other interested parties in public sessions that
12 ultimately resulted in a stipulated agreement with the Missouri Public
13 Service Commission ("Missouri Commission") Staff, the Missouri Office of
14 Public Counsel, and other interested parties. The upshot of this
15 agreement is that, after an initial rate freeze through 2006, KCPL will be
16 able to file annual rate cases for 2007 through 2009, without the risk of
17 intervention by signatories to the agreement.
18
19 It is noteworthy that rate relief in those proceedings will be based upon the
20 highly unusual but extremely innovative step of explicitly relying upon
21 S&P's publicly-disseminated credit ratio guidelines to ensure that KCPL's
22 key financial measures would remain at levels adequate for its "BBB"
23 credit ratings. In addition, the plan incorporates an option for the company

to implement an interim power cost adjustment clause during the life of the agreement. On July 28, 2005, the Missouri Commission unanimously approved the stipulated agreement and the Kansas Corporation Commission offered its unanimous support shortly thereafter.[10]

Q. HOW DID THE CREDIT RATING COMMUNITY REACT TO THE AGREEMENT NEGOTIATED BY GREAT PLAINS AND KCPL?

A. Positively. S&P viewed it very favorably, stating that the proposed proactive regulatory plan would provide "an adequate framework for rate relief both during and after" KCPL's $1.3 billion five-year capital investment program. S&P highlighted the availability of an interim power cost adjustment clause and the formulaic nature of the process of determining future rate relief in a less adversarial setting as supportive of S&P's affirmation of KCPL's and Great Plains Energy's credit ratings. Moreover, the plan's acknowledgement of the important connection between future rate levels and key credit rating financial measures supports the position that APS presented in its last general rate case. Finally, I found it noteworthy in view of the issues being considered in this APS proceeding that S&P concluded that:

> "Exceptionally strong regulatory support, project execution, and debt reduction could lead to an improved outlook for KCPL and Great Plains [, while, i]n contrast, failure to secure adequate rate relief or a fuel cost recovery mechanism by 2007 could have

[10] S&P Research: "MPSC Approval of Regulatory Plan Will Not Affect Kansas City Power & Light's Rating," July 29, 2005; "Kansas City Power & Light Begins Implementation of Long-Term Energy Plan," Business Wire, August 9, 2005.

negative credit implications."[11]

Q. ARE THERE OTHER RECENT EXAMPLES WHERE PROACTIVE REGULATION RESOUNDED TO POSITIVE EFFECT ON WALL STREET?

A. Yes. Last year, the Colorado Public Utility Commission ("Colorado Commission") approved a Comprehensive Settlement Agreement ("CSA") between Public Service Co. of Colorado ("PS Colorado") and major environmental and consumer groups. Similar to the Missouri agreement I just described, the intent of the CSA is to allow PS Colorado to proceed with a substantial capital investment program related to new coal-fired plant construction and environmental steps necessary to allow existing coal-fired power plants to meet current and future emission controls. Significantly, the CSA was designed to allow PS Colorado to proceed with its large construction program while ensuring that the company's credit profile would not be weakened by that costly effort.

Q. HOW EXACTLY WAS THE CSA STRUCTURED TO MAINTAIN PS COLORADO'S CREDIT PROFILE?

A. In a report published on March 29, 2005, S&P described the major points of the CSA that are pegged to PS Colorado's credit quality:

- PS Colorado will be allowed to increase equity up to 60% of capital to reflect the economic cost incurred by its existing purchased-power contracts,
- PS Colorado will be allowed to add "construction work in

[11] S&P Research Update: "Great Plains Energy and Unit Ratings Affirmed; Outlook Stable," April 1, 2005.

progress" (CWIP) to rate base in amounts that will be determined by current senior unsecured debt ratings and the capital structure,

- Plant construction costs (up to a confidential cap) and environmental control costs related to the 750 MW coal-fired Comanche Project are deemed prudent and are recoverable in rates, and
- The major costs associated with implementing this agreement are to be deemed prudent and recoverable in rates.[12]

Q. DOES S&P HAVE A POSITIVE VIEW OF THE CSA AND THE COLORADO COMMISSION'S APPROVAL OF IT?

A. Yes they do. S&P focuses on the fact that growing generation capacity needs will force utility managements to "consider strategies that will gain them the support of many diverse constituencies, many of whom will otherwise assuredly oppose their related rate requests before state regulators." Describing the CSA as "a successful outcome in this respect," S&P concludes that:

> "With this agreement, PS Colorado has effectively addressed the future costs associated with adequate supply and environmental compliance with a plan that will permit timely recovery of those costs. *This is a major step forward in eliminating the tug-of-war* over cost recovery that, in the past, has plagued the credit of so many utilities when the time comes to build again."

Q. YOU EARLIER SPOKE ABOUT MANDATORY EXPENDITURES REQUIRED OF UTILITIES, EITHER BY LAW OR REGULATORY POLICY, AND HOW THE FINANCIAL COMMUNITY VIEWS THE POTENTIAL RECOVERY OF SUCH COSTS. CAN YOU ELABORATE ON THAT THOUGHT?

[12] S&P Research: "PS Colorado Garners Support for Credit Quality Up-Front; A Viable Model for the Electric Industry?," March 29, 2005.

1 A. Yes I can. Good examples on this point are the state commissions that
2 have proactively faced up to the likelihood that utilities will have to expend
3 substantial sums of money for environmental compliance in the future, and
4 have acknowledged that an early start on such activities that is facilitated
5 by upfront regulatory support serves the public interest. For example,
6 early regulatory action on environmental cost recovery mechanisms has
7 already occurred in the following states:

8 • Florida (Fla. Stat. Sec. 366.8255 (2005): stating that electric
9 utilities may submit a petition requesting recovery of the utility's
10 proposed compliance activities and projected environmental
11 costs, which are recoverable following a prudence review);
12 • West Virginia (W. Va. Code Sec. 24-2-1g (2005): commission
13 may authorize "rate-making allowances" for investments in clean
14 coal and clean air technology facilities or for purchases of power
15 from clean coal technology facilities within the state);
16 • Kentucky (KRS Sec. 278.183 (2004): allows a utility to recover,
17 through an environmental surcharge, costs of compliance with
18 laws that apply to coal combustion wastes and by-products);
19 and
20 • Indiana (Burns Ind. Code Ann. Sec. 8-1-27-6, 8-1-27-8 (2004):
21 utility may voluntarily submit an environmental compliance plan
22 to recover costs to comply with requirements of Clean Air Act
23 Amendments of 1990, which are assessed based on

reasonableness, least cost strategy, and the public interest).

Such proactive regulatory treatment for recovery of prudent expenditures that are made by utilities to further public policy goals is viewed very favorably by the Wall Street financial community.

Q. DO YOU SEE SPECIFIC APPLICABILITY OF THESE POSITIVE REGULATORY OUTCOMES AND THE ISSUES FACING THIS COMMISSION?

A. While there is certainly some clear applicability between the pending issues and concerns in those other jurisdictions and what is occurring in Arizona – *e.g.* the need for additional capacity, the use of a power supply adjustment mechanism, credit rating stresses of "BBB" credit profiles, and consideration of environmental compliance activities that will be escalating in the future – I think the more important message to take away is the benefit that can result for both customers and financial investors from the proactive involvement by an individual commission in seeking to solve the particular stresses confronting the regulated utilities within its jurisdiction. In other words, I am praising the proactive nature of the regulatory responses I described as opposed to embracing the idea that there is a "one-size-fits-all" solution that can be taken from the regulatory process in one state and plugged into another.

Q. WHY SHOULD REGULATORS BE CONCERNED WITH THE "UPS-

1 **AND-DOWNS" OF A UTILITY'S FINANCIAL SITUATION?**

2 A. I return to some of the themes I discussed in my testimony in the last APS
3 rate case. Customers benefit when their utility is able to easily access the
4 debt and equity markets on reasonable terms when needed to fund
5 infrastructure requirements necessary to ensure appropriate levels of
6 reliability or to meet growth in customer demand. This is especially true
7 when volatility in the energy/utility sector (like we have experienced during
8 the past few years) has tightened up liquidity within the capital markets.
9 While utility competition has not yet flourished within the consumer
10 marketplace, utilities compete with each other everyday for capital
11 financing. The ability to access the debt market when needed is important
12 because it allows a company to carry out its infrastructure and
13 environmental compliance planning on a timetable of its own formulation,
14 one that can maximize potential efficiencies within the process. Financial
15 strength helps to achieve this goal.
16
17 **Q. ARE THE VIEWS YOU EXPRESS HERE ABOUT PROACTIVE**
18 **REGULATORY BEHAVIOR AND SENSITIVITY TO A REGULATED**
19 **UTILITY'S FINANCIAL SITUATION CONSISTENT WITH THE POLICIES**
20 **YOU SUPPORTED AS A STATE REGULATOR?**
21 A. Yes, very much so. As I explained in my testimony in this Commission's
22 proceeding to review the settlement agreement of APS' last general rate
23 case, the most pressing issues I faced during my six years as a

1 Commissioner and then Chairman at the Michigan PSC were the financial
2 condition of the state's two largest utilities, one electric (Detroit Edison)
3 and the other electric and gas (Consumers Power), and the resulting
4 effect on customers and the prospects for reliable service.
5
6 I described how Detroit Edison was reeling financially from construction
7 expenditures at its Fermi nuclear plant and Consumers Power's
8 abandonment of its Midland nuclear facility had placed it in a position
9 where, without extraordinary rate relief, it likely would have had to file for
10 bankruptcy. In 1988, the Michigan Commission approved a five-year rate
11 settlement agreement for Detroit Edison that allowed the company to
12 return to a degree of financial health during the term of the agreement
13 and thereafter. With regard to Consumers Power, parties to a number of
14 proceedings related to the abandonment of the Midland nuclear plant and
15 its transition into a cogeneration facility negotiated during virtually my
16 entire six-year tenure on the Michigan PSC before bringing to the
17 Commission a global settlement of pending issues. The Michigan
18 Commission's approval of that major settlement agreement allowed
19 Consumers Power to also return to financial health.
20
21 I highlighted this sensitivity to a regulated utility's specific situation in an
22 opinion piece I authored in Public Utilities Fortnightly. I emphasized the

fact that good regulatory policies flowed from good communication between the regulator and the regulated:

> "As a state regulator, I lived by one cardinal rule: The best consumer and investor protection is open and frank communication between regulators and utility management."[13]

Consistent with this regulatory "golden rule," I think it is important that the Commission and APS be on the same page with regard to beneficial capital investment, with the corollary that capital utilization in tune with this "meeting of the minds" should be recoverable in rates.

Starting my first day as a state regulator and carrying through my various roles within the utility industry, I have seen that there is not one exact level of system reliability that can be pinpointed and translated into a necessary spending level. Rather the process should be dynamic, with ongoing communication to ensure that the customer receives reliable service that can be counted upon, and that the investor is fairly compensated for the requisite level of financial commitment to maintain such level.

While these general principles I have enunciated are relevant in every jurisdiction, a record of regulatory distinction – respected by both customers and investors -- comes about where solutions are keyed to the particular problems at hand. I offered up examples in Michigan of what

[13] "Perspective: Don't Fence Me Out," Public Utilities Fortnightly, October 2004.

the problems were long ago along with an explanation of the solutions the Michigan Commission found appropriate. I also have pointed to recent examples in Missouri, Kansas, and Colorado. But I am NOT recommending that any of the paths that regulators took under their particular circumstances are right for the concerns that this Commission is facing. Rather I am encouraging a sensitivity to local concerns and circumstances followed by a proactive response that allows prudent expenditures made for the benefit of customers to be timely recovered.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

APPENDIX A

STEVEN M. FETTER

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Education University of Michigan Law School, J.D. 1979
Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. (Communications) 1974

April 2002 – Present
President – REGULATION UnFETTERED – Rumson, NJ

Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy and telecommunications sectors; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; and skills training in ethics, negotiation, and management efficiency.

- Service on Boards of Directors of: CH Energy Group (Chairman, Audit Committee; Member, Governance and Nominating, Compensation, and Executive Committees), National Regulatory Research Institute (at Ohio State University), Keystone Energy Board, and Regulatory Information Technology Consortium; Member, Wall Street Utility Group and American Public Power Association; Participant, Keystone Center Dialogue on Financial Trading and Energy Markets.

October 1993 – April 2002
Group Head and Managing Director; Senior Director -- Global Power Group, Fitch IBCA Duff & Phelps – New York/Chicago

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance.

- Led an effort to restructure the global power group that in three years time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

- Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including

The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

- Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002
Consultant – NYNEX – New York, Ameritech – Chicago, Weatherwise USA – Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993
Chairman; Commissioner – Michigan Public Service Commission – Lansing

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

- Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

- Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant twelve-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

- Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability;

Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987
Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary -- U.S. Department of Labor -- Washington DC

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (U.S. Labor Law and the Future of Labor-Management Cooperation, w/S. Schlossberg, 1986).

January 1983 - August 1985
Senate Majority General Counsel; Chief Republican Counsel -- Michigan Senate -- Lansing

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 - January 1983
Assistant Legal Counsel -- Michigan Governor William Milliken -- Lansing

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982
Appellate Litigation Attorney -- National Labor Relations Board -- Washington DC

Other Significant Speeches and Publications

- Perspective: Don't Fence Me Out (Public Utilities Fortnightly, October 2004)
- Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998)(unpublished)
- Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)
- The Feds Can Lead...By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)
- Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)

- Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)

- Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

REBUTTAL TESTIMONY OF STEVEN M. FETTER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

EXHIBIT
APS 24
admitted

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REBUTTAL TESTIMONY OF STEVEN M. FETTER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven M. Fetter, and my business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, Nevada 89014.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President of REGULATION UnFETTERED, an energy advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London, as Group Head and Managing Director of the Global Power Group. Prior to my time at Fitch, I served as Chairman of the Michigan Public Service Commission.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. SUMMARY

Q. COULD YOU SUMMARIZE YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In this Rebuttal Testimony, I conclude that, if the Arizona Corporation Commission ("Commission") were to accept the positions put forward by either Commission Staff or RUCO in this proceeding, the financial condition of Arizona Public Service Company ("APS") would suffer significant deterioration, leading in all likelihood to a credit rating downgrade to below investment-grade level. Such negative rating actions would have a deleterious

effect on APS customers as access to capital would become more expensive, leading ultimately to higher rates.

In addition, I discuss the concept of regulatory lag, which undercuts the ability of a regulatory body to be timely in its decision-making, both as it relates to the Staff and RUCO recommendations and in response to Chairman Hatch-Miller's letter to this docket dated July 21, 2006. I explain how such delay in implementation of regulatory policy determinations can have a negative impact on both regulated utility companies as well as their customers.

III. CREDIT RATINGS

Q. WHAT CREDIT RATINGS DOES APS CURRENTLY HOLD?

A. APS' current Standard & Poor's ("S&P") ratings for senior unsecured debt are "BBB-", with a Stable ratings outlook. Moody's Investors Service ("Moody's") senior unsecured credit ratings for APS are "Baa2", with a Negative outlook.

These ratings designations for APS equate to lowest-quality investment-grade debt.

Q. PLEASE GENERALLY DESCRIBE THE CREDIT RATINGS PROCESS.

A. Credit ratings reflect a credit rating agency's independent judgment of the general creditworthiness of an obligor or the creditworthiness of a specific debt instrument. While credit ratings are important to both debt and equity investors for a variety of reasons, their most important purpose is to communicate to investors the credit strength of a company or the underlying credit quality of a particular debt security issued by that company. Credit rating determinations are made through a committee process involving individuals with knowledge of a company, its industry, and its regulatory environment. Rating designations of

both Fitch and S&P have "BBB-" as the lowest investment-grade rating and "BB+" as the highest non-investment-grade rating. Comparable rating designations of Moody's are "Baa3" and "Ba1", respectively. (I explain below the consequences of a utility's credit ratings falling below investment-grade.)

Corporate credit ratings analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income issuers. A credit rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. It also at times incorporates some consideration of ultimate recovery of investment in case of default or insolvency. Ratings can also be used by contractual counterparties such as fuel or power suppliers to gauge both the short-term and longer-term health and viability of a company, and they can directly impact the terms on which the counterparties are willing to do business.

Q. PLEASE DESCRIBE THE QUALITATIVE FACTORS USED BY THE RATING AGENCIES.

A. The most important qualitative factors include regulation, management and business strategy, and, for electric utilities, access to energy, gas and fuel supply with recovery of associated costs.

Q. CAN YOU SHARE YOUR THOUGHTS ON THE IMPORTANCE OF "REGULATION" WITHIN THE CREDIT RATINGS PROCESS?

A. Yes. Regulation is a key factor in assessing the credit profile of a utility because a state public utility commission determines rate levels (recoverable expenses including depreciation and operations and maintenance, fuel cost recovery, and return on investment) and the terms and conditions of service.

Since the announcement of California's restructuring plan in 1994, regulation has become an even more important variable as the nature of a utility's responsibilities in providing energy services to customers has undergone dramatic change. In some states, industry restructuring was the result of plans formulated by the state legislature. In other states, the regulators, rather than the legislators, have determined the nature and pace of restructuring.

Under restructuring plans, utilities have been directed to foster the development of competitive alternatives to the services they provide, materially scale down their operations for certain functions, often including divestiture of generation, while at the same time, retaining what is commonly referred to as the "provider of last resort" ("POLR") responsibility. As the POLR, a utility bears the ultimate responsibility to serve all of the customers in its service territory in the event of intermittent defaults or permanent failures by competitive suppliers to reliably discharge their responsibilities.

This situation affects utility investors' decisions because, before major energy investors will be willing to put forward substantial sums of money, they will want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a rapidly evolving industry. Investors also want assurance that regulators' decision-making will be fair, timely and will have a significant degree of predictability.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by the commissions. If a regulatory body were to encourage a company to make investments based upon an expectation of the opportunity to earn a reasonable return, and then did not apply regulatory

principles in a manner consistent with such expectations, investor interest in providing funds to such utility would decline, debt ratings would likely suffer, and the utility's cost of capital would increase.

Q. IN VIEW OF THESE UNPRECEDENTED EVENTS DURING THE PAST FIVE YEARS, DO THE ACTIONS OF UTILITY REGULATORS TODAY DRAW EVEN MORE ATTENTION FROM THE FINANCIAL COMMUNITY?

A. Yes, without a doubt. Regulation has always garnered the attention of Wall Street, but, years ago, seemingly only during the days leading up to a commission's rate case decision. This began to change around the time that Fitch hired me in 1993 to serve in the role of regulatory analyst and assess regulatory and political factors that could impact upon a utility's financial strength. When California announced its ultimately ill-fated restructuring plan in 1994, the entire financial community, especially Fitch and its rating agency competitors S&P and Moody's, took much greater notice of regulators and how they carried out their responsibilities, not only with regard to rate-setting, but even more importantly the manner in which they undertook to change the way the entire utility industry had operated for over 100 years.

S&P highlighted the continuing importance of regulation to the financial community in two recent reports. In a report entitled "New York Regulators' Consistency Supports Electric Utility Credit Quality," S&P offered general thoughts on the importance of regulation that apply within but also far beyond the borders of New York:

> Regulation defines the environment in which a utility operates and greatly influences a company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy as a result of supportive regulation. Conversely, an unpredictable or antagonistic regulatory environment can

> undermine the financial position of utilities that are operationally very strong.
>
> To be viewed positively, regulatory treatment should be timely and allow consistent performance over time, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory policies...[1]

Earlier, S&P had discussed how changing circumstances within the utility industry have elevated the importance of regulatory policies:

> In recent years, [S&P's] emphasis on the decisions by state commissions has been less pronounced simply because so many jurisdictions have been working through multiyear restructuring transition periods. During this time, rates were frequently frozen, and companies and customers have been adjusting (albeit with limited success) to the opportunity that customers have to choose alternate power suppliers.
>
> But the confluence of the approaching end of these transition periods and the growing need in certain regions of the country for significant resource additions is quickly returning the regulatory arena to center stage. In assessing the regulatory environment in which a utility operates, [S&P's] analysis is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag that may prove detrimental if a utility needs rate relief.[2]

Q. NEXT, YOU MENTIONED MANAGEMENT AND BUSINESS STRATEGY AS ANOTHER IMPORTANT QUALITATIVE FACTOR. PLEASE DESCRIBE THAT FACTOR.

A. An assessment of quality and depth of management personnel is made and consideration is given as to how a company's strategic plans and risk profile fit

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[1] S&P Research: "New York Regulators' Consistency Supports Electric Utility Credit Quality," August 15, 2005.

[2] S&P Research: "U.S. Utility Regulation Returns to Center Stage," April 14, 2005.

within its overall business and local regulatory environment, as well as how effective management is at implementing those plans. This includes consideration of management's ability to interact with regulators and executive and legislative branch officeholders in a way that allows the company to carry out its operations effectively and efficiently for the benefit of its key constituencies, including small and large customers and shareholders. Moreover, in view of the volatile environment within the utility sector at this time, an assessment is made of the utility's capability to respond to extraordinary occurrences, including events outside management's control.

Q. PLEASE DESCRIBE THE FINAL QUALITATIVE FACTOR THAT IS SO IMPORTANT TO ELECTRIC UTILITIES -- ACCESS TO ENERGY, GAS AND FUEL SUPPLY WITH RECOVERY OF ASSOCIATED COSTS?

A. Access to secure and reasonably-priced sources of energy and gas is a key factor for a utility. Equally important are the extent to which the utility recovers its costs of serving its core customers, the mechanisms for timely recovery, and the level of confidence that investors have that the state commissions will stand behind the established recovery methodology, even under potentially difficult circumstances, such as market volatility and increasing prices.

Q. COULD YOU PLEASE DESCRIBE THE QUANTITATIVE FACTORS USED BY THE RATING AGENCIES?

A. Financial performance continues to be a very important element in credit rating analysis. Credit rating agencies and fixed-income analysts utilize analytical ratios to understand the credit profile of a utility, with S&P publicly explaining the three financial measures that it views as most important in its analysis of utility companies: funds from operations ("FFO") / interest coverage; FFO / total debt; and total debt / total capital. I note that the rating agencies adjust

these key ratios to reflect imputed debt and interest-like fixed charges flowing from long-term contracts and certain other off-balance sheet obligations.

Building upon those key ratios, S&P has been the most explicit of the three major rating agencies in explaining how it views the interplay between quantitative and qualitative factors. As part of its utility credit rating process, S&P arrives at a "Business Profile" designation that it considers in concert with its "Utility Financial Targets." S&P's Utility Financial Targets, which encompass the quantitative ratios listed above, differ depending upon a utility's Business Profile rating. The weaker the Business Profile designation, the stronger the Financial Targets must be in order to obtain any given credit rating.

Q. WHAT DOES S&P'S BUSINESS PROFILE DESIGNATION REFLECT?

A. The Business Profile designation reflects S&P's assessment of qualitative factors such as regulation, markets, operations, competitiveness, and management. This designation is on a scale of '1' (meaning very strong) to '10' (meaning very weak). Designations of 1 and 2 indicate "Well Above Average" business position; 3 and 4 indicate "Above Average"; 5 and 6 indicate "Average"; 7 and 8 indicate "Below Average"; and 9 and 10 indicate "Well Below Average."

Q. GENERALLY, WHAT BUSINESS PROFILES APPLY TO UTILITIES?

A. Distribution and transmission companies usually have Business Profile ratings of '2' through '4.' Power generation and energy trading companies with significant commodity price risks usually have Business Profile ratings of '7' through '9.' Vertically-integrated utilities usually have Business Profile ratings in the middle of the scale, in the '4' to '6' range. APS' Business Profile is a "6", at the low end for a vertically-integrated utility.

Q. WHY IS S&P'S METHODOLOGY MEANINGFUL TO YOU?

A. I believe that S&P's methodology helps facilitate a general understanding of how a credit rating agency carries out the process of formulating a credit rating and the factors that go into such a determination.

Q. WHILE RETURN ON EQUITY ("ROE") IS NOT DIRECTLY RELATED TO BONDHOLDER REQUIREMENTS, CAN YOU SHARE YOUR THOUGHTS ON WHY THE LEVEL OF ROE AUTHORIZED BY REGULATORS IS OF CONSEQUENCE TO INVESTORS IN DEBT SECURITIES?

A. The existence of equity in a utility capital structure provides a company with the capacity to tolerate the normal ups and downs that come with operational business risks, while also providing a cushion to a company's lenders and bondholders (fixed-income investors). Fixed-income investors look to the earnings of shareholders as an additional margin available for the payment of interest and principal under adverse business circumstances.

IV. CREDIT RATING ANALYSIS OF APS

Q. YOU EARLIER REFERRED TO APS' CREDIT RATINGS AS EQUATING TO LOWEST-QUALITY INVESTMENT-GRADE DEBT. WHAT RATING CATEGORIES DO YOU MEAN WHEN YOU USE THIS DESCRIPTION?

A. I am referring to long-term credit ratings at the lower end of the "BBB" category. Within the "BBB" category, differentiations are made between "BBB+"/"BBB"/and "BBB-". "BBB-" is the lowest rating an issuer can be assigned without falling below investment grade into "junk bond" status. Moody's comparable rating scale uses "Baa1", "Baa2", and "Baa3", the lowest investment-grade rating.

Q. IN YOUR OPINION, DO RETAIL CUSTOMERS BENEFIT FROM HAVING UTILITY DEBT RATED ABOVE APS' CURRENT LEVEL OF LOW-QUALITY INVESTMENT-GRADE DEBT?

A. Yes. Let me first focus on mid-quality investment-grade debt at the "BBB+" level. The benefit to customers is that a utility with debt having at least a mid-quality investment-grade rating is able to raise debt capital when needed to fund infrastructure requirements necessary to meet growth in customer demand, and can refinance maturing debt on more reasonable terms than a lower credit quality utility. This is especially true when volatility in the energy/utility sector (like we have experienced during the past five years) has tightened up liquidity within the debt market. Moreover, the ability to access the debt market when needed is important because if a company needs to expand or upgrade its generation, transmission or distribution infrastructure to maintain system reliability or undertake construction projects for environmental compliance, debt funding is an advantageous source of capital as it is typically more economical than equity financing. As ratings trend down to the lowest-quality investment-grade level of "BBB-", APS' current level, the utility industry's continuing unsettled state neutralizes many of benefits I have described above.

Q. WHAT ARE SOME OF THE CONSEQUENCES OF A UTILITY'S CREDIT RATING FALLING BELOW INVESTMENT-GRADE QUALITY?

A. There would be a marked change in the investor profile for that utility. Major utility investors such as insurance companies and pension funds operate under legal restrictions that severely limit their ability to invest in below investment-grade debt instruments, or "junk bonds." Mutual funds could also be affected based upon what a particular fund has communicated to investors as to its investment profile. Moreover, a utility with a "junk bond" rating would likely have to post bond or put up cash as collateral in various contracts (such as for energy supply) or to meet certain regulatory commitments (such as Independent

System Operator agreements or environmental remediation requirements). This, of course, would come at a time when access to a utility's existing credit facilities likely would be limited by the financial institutions previously providing the assistance. Finally, a utility with below investment-grade status would be unable to access the commercial paper (short-term debt) market. Commercial paper is a key source of funding for utilities, most of which have revenues that vary substantially depending upon the time of year, and loss of access to that market can severely impair financial liquidity.

Q. PLEASE EXPLAIN THE STEPS YOU TOOK TO ASSESS THE POTENTIAL CREDIT RATING IMPACT FOR APS AS A RESULT OF THIS RATE PROCEEDING?

A. I requested from the Company three financial forecasts covering the period 2006 through 2008, assuming a May 1, 2007 effective date[3]: one using the financial information from the APS rebuttal filing as updated with new information; a second one utilizing financial information underlying the Commission Staff recommendation in this proceeding <u>including</u> Staff's projected PSA proposal under some favorable assumptions; and a third one doing the same thing with the RUCO recommendation.[4] (See DEB-1RB, DEB-2RB, and DEB-3RB attached to the testimony of APS witness Donald Brandt). I have utilized the S&P methodology and the forecast data in the analysis that follows, indicating the likely credit rating impacts under both the Commission Staff position and the RUCO case, compared against the likely result if the updated APS position were to be adopted by the Commission.

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[3] Credit metrics for the three forecasts are provided in the testimony of APS witness Donald Brandt.

[4] As explained earlier, rating agencies often impute debt and interest to reflect certain off-balance sheet obligations including long-term leases. Accordingly, the Company has adjusted the three forecasts to account for

Q. PLEASE DESCRIBE THE RESULTS OF YOUR ANALYSIS.

A. Using the Commission Staff position even including a number of favorable assumptions concerning their proposal to revise the PSA calculation to allow projected fuel and purchased power costs, I found that APS' credit ratings would in all likelihood fall below investment-grade quality. While funds from operations (FFO) interest coverage weakens from 3.9x (times) to 3.4x by 2008, that measure remains at "BBB" investment-grade levels during the forecast period. However, the other two key S&P measures indicate a much more negative situation. FFO/Total Debt, which S&P has indicated is its most important ratio because it incorporates measures of both cash flow and debt, begins in 2006 at 17.6%, equating to a below-investment-grade rating in the "BB" category, and falls further during the subsequent two years to 15.1%, in the middle of the "BB" category. Total debt to total capital begins the forecast period at 54.6%, consistent with the investment-grade "BBB" category, but by the next year falls below investment-grade for the remainder of the forecast period. Forecasts under the Commission Staff case indicate that APS would likely not be able to maintain its investment-grade status once this proceeding has concluded. See, for example, S&P's recent statement:

> Of the staff's recommended increase, about 9.1% is related to base fuel and purchased power rates, but falls short by about $105 million of APS' requested increase for these costs. The remainder of the $141 million staff-recommended reduction is based on non-fuel items, with a large portion of the difference attributable to staff's suggestion that APS' authorized ROE be set at 10.25%, relative to the 11.5% that APS is seeking ... The stable outlook for PWCC and APS' rating is premised on the ACC continuing to provide sustained regulatory support that addresses permanent rate relief and manages

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the credit rating agencies' imputation of debt and interest expense attributable to power purchase obligations and operating leases such as the Palo Verde Unit 2 Sale and Leaseback.

> the deferral balances downward over a reasonable time frame. A negative rating change or outlook could result if the size of the deferred balances materially increases...[5]

and similar sentiments from Moody's, which, acting upon its earlier warnings, downgraded the credit ratings of APS on April 27, 2006:

> The negative outlook ... reflects the potential for weaker performance if the Palo Verde nuclear facility does not return to normal operating performance by mid-summer as is expected, or if other significant pending regulatory proceedings for APS do not provide for relatively timely recovery of increased costs, particularly those for fuel and purchased power.[6]

The results under the RUCO case would cause an even more severe negative impact on APS' credit profile, thus also likely driving the Company into below investment-grade or "junk bond" status. The key FFO to total debt measure begins in 2006 at 17.6% in the "BB" below investment-grade category, and, by 2008, is just above the *bottom* of that already weak sub-investment category at 12.9% (with the "BB" category defined as 18% down to 12%). Total debt to total capital of 54.6% is at investment-grade level at the end of 2006, but worsens into below investment-grade status the next year (58.6%) and close to the *bottom* of the "BB" category in 2008 (60.9% with a bottom boundary of 62%). FFO interest coverage is within the "BBB" for the first two years of the forecast period (3.9x and 3.5x), but then drops in 2008 to the 3.0x dividing line between investment-grade and below investment-grade ratings. I believe that adoption of the RUCO case would, like the results from the Commission Staff case, quickly lead to below investment-grade determinations from the rating agencies.

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[5] S&P Research Summary: "Arizona Public Service Co.," August 31, 2006.

Q. PLEASE SHARE THE RESULTS OF YOUR ANALYSIS OF THE UPDATED APS POSITION?

A. Under the modified APS case, both total debt to total capital and FFO interest coverage reside within the "BBB" investment-grade category for the entire forecast period, with the former varying between 3.9x and 4.0x (on a scale of 4.2x down to 3.0x) and the latter spanning 54.6% to 52.1% (with the "BBB" category defined as 48% to 58%). I note that APS' FFO to total debt measures of 17.6% in 2006, 19.2% in 2007 and 17.5% in 2008 skirt just below and just above the 18% investment-grade/non-investment-grade dividing during the forecast period.

Thus, while I believe that the three measures taken together will equate to investment-grade status for APS, the continuing weakness in the key FFO/total debt ratio indicates to me that the Company case will not lead to a significantly-stronger credit profile for APS than its current "BBB-" corporate rating level from S&P. I note S&P's comment from two weeks ago: "Given the regulatory challenges over the near term and the potential for continued operational challenges at Palo Verde, there is little opportunity for a positive rating action at this time."[7]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE CREDIT IMPLICATIONS OF YOUR ANALYSIS.

A. If the Commission were to adopt either the Commission Staff position or RUCO's case, APS' credit ratings would likely suffer a rating downgrade to below investment-grade level. I believe this would represent the first time in the

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[6] Moody's Research: "Moody's Confirms Ratings of Pinnacle West (Baa3 Issuer Rating); Outlook Negative," May 8, 2006.

[7] S&P Research Summary: "Arizona Public Service Co.," August 31, 2006.

Company's 100-year plus history that it will have lost its investment-grade credit rating. If such a downgrade were to occur, APS' access to the already tightening capital markets would become more restricted, increasing its cost of capital and limiting its financial flexibility. The situation created by such a scenario would have a negative impact on both customers, in the form of higher capital costs translating into higher rates, and investors, through the loss in value of equity and debt holdings.

Q. IN GENERAL, WOULD A CREDIT RATING AGENCY ACT ON A COMPANY'S POTENTIAL DOWNGRADE IMMEDIATELY UPON ISSUANCE OF A REGULATORY ORDER THAT FORETELLS OF LIKELY DETERIORATION, OR WOULD IT WAIT UNTIL THE DETERIORATION IS EVIDENT IN THE COMPANY'S FINANCIAL STATEMENTS?

A. Credit ratings are based on prospective financials. As such, as soon as the final Commission order is issued, the credit rating agencies would analyze the likely financial impacts and provide the Company with an immediate opportunity to provide additional relevant information that should be considered. A rating change, if warranted, would follow shortly thereafter.

It is important to emphasize that in view of the volatility among utility credit ratings during the past five years, it is far easier for a utility's ratings to slip down due to a financial "ding" than for that same utility to regain its earlier status once the deficiency has been remedied. For that reason, I do not believe that any weakening of APS' credit profile now could, if the Commission changed its mind, be easily remedied in the Company's next rate proceeding. This would be especially so if the downward movement crossed APS into below investment-grade status. My advice to utility companies, investors and

regulators alike is that nothing should be taken for granted in the current utility investing environment.

Q. ASIDE FROM THE EFFECTS ON APS' FINANCIAL CONDITION AND CREDIT RATIOS, DO YOU FORESEE ANY OTHER POTENTIAL ADVERSE CREDIT IMPLICATIONS RESULTING FROM AN ADVERSE DETERMINATION BY THE COMMISSION FOR APS IN THIS PROCEEDING?

A. As I previously explained, an important element of the credit evaluation of electric utilities is an assessment of regulation. Currently, Arizona is viewed by the financial community as a difficult regulatory climate. For this reason, credit rating analysts will closely monitor this proceeding to see whether an improving trend becomes evident. However, if the Commission were to deny appropriate rate relief, the rating agencies would make an assessment of the reasons for the decision and determine whether they supported the maintaining of their current view. A decidedly negative assessment of Arizona regulation could have unfavorable credit rating implications, not only for APS, but potentially for all utilities subject to the rate making authority of the Commission.

V. <u>REGULATORY LAG</u>

Q. ARE YOU FAMILIAR WITH THE CONCEPT OF REGULATORY LAG?

A. Yes I am. The term is often used to describe delays occurring from the time a utility files for a rate increase (or commission staff or intervenor party files for a show cause seeking a decrease in rates) and the time that a regulatory body issues its decision and implements such rate change. While I accept that definition, when I served as chairman of the Michigan Public Service Commission, I viewed the term in a much broader context.

Q. HOW SO?

A. At the time that I was appointed to the Michigan PSC, the agency had a reputation for high-quality members and staff who shared an unfortunate inability to decide any types of cases on a timely basis. After I became chairman of the Michigan PSC three years later, I set as a goal the elimination of the agency's case backlog within two years. Michigan law provided a nine-month target for rate proceedings, but, upon missing that deadline, all that the commission had to do was inform the governor and legislative leaders that the target had been missed. The law did not provide for any sanctions.

Q. WHAT WERE THE RESULTS UNDER THAT STATUTE?

A. I am happy to say that the Michigan PSC was always timely in sending letters to those public officials informing them that we had missed the statutory target. Unfortunately, by the time I became chairman, the agency had a case backlog in excess of 50 matters, some that had been pending for years. I think my proudest accomplishment was in energizing my fellow commissioners and staff members to eliminate that backlog within six months, the first time the agency had enjoyed a clean slate in 23 years.

Q. DO YOU SEE APPLICABILITY OF YOUR EXPERIENCE HERE IN ARIZONA?

A. Yes, very much so. I would not presume to tell the Arizona Commission how it should organize its internal processes for maximum efficiency. I would not even presume to say that I have better ideas for reducing regulatory lag than APS or other companies regulated by the Commission. I encourage you to review and consider the ideas for reducing regulatory lag put forward by APS witnesses Steven Wheeler and Donald Brandt, as well as the thoughts of any other stakeholders who believe they know what can improve the process. The issue is

important not only to regulated utilities in a growing service territory or customers when rates deserve to go down, but also especially to financial community investors who spend everyday matching up risk and return. They must consider whether regulatory delay will be mitigated by rates under bond or some type of carrying charges in determining where to invest their funds. Under such circumstances, Arizona is competing with other jurisdictions all the time. Competitiveness in this context is measured by fair returns and timely processes.

Q. HAVE YOU SEEN SOME PROGRESS IN ARIZONA WITH REGARD TO THIS ISSUE?

A. Yes. The power supply adjustor was certainly a step in the right direction, including the Commission's continuing efforts to better align the amount and timing of recovery with the level of expenditures and when they were spent. On the other hand, APS general rate proceedings still take a very considerable amount of time, and reliance on a historical test period only exacerbates problems of regulatory lag. During my time as a regulator, I viewed that working toward more efficient processes was a never-ending task, one whose goal was to take one beneficial step and then seek to build upon it with another. And maybe it is because of where I came from, but I sincerely believe that, after stakeholders have had their opportunity to present views as to how to fix the process, the best knowledge base for formulating and implementing innovative and effective change still resides among those who are involved with the issues every day – those within the four walls of this Commission. I encourage you to take on that challenge.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

EXHIBIT
APS-25
Admitted

REBUTTAL TESTIMONY OF THOMAS J. CARLSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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REBUTTAL TESTIMONY OF THOMAS J. CARLSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Thomas J. Carlson. I am the Portfolio Manager for Arizona Public Service Company ("APS" or "Company") Regulated Marketing and Trading Division. In that role, I am responsible for procuring wholesale purchased power and natural gas for APS native load needs and also the marketing of surplus APS generation and natural gas.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree from the University of South Dakota in 1977. Prior to coming to APS, I worked in marketing and market research positions with the airline and motor transportation industries. I held a similar position when I joined APS in 1988. In 1992, I began working in the gas trading and fuel management area of the Company, rising to Director of Generation Fuel Procurement for APS in 2001 and to Portfolio Manager in 2004.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My testimony will briefly describe APS' natural gas and purchased power hedging philosophy and policies relating to the procurement of the natural gas and purchased power needed to serve our native load, and also discuss certain aspects of the Direct Testimony filed by Staff witness John Antonuk and RUCO witness J. Richard Hornby relating thereto.

II. SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Yes. APS incorporates extensive use of financial and physical contracts to minimize commodity price volatility when purchasing natural gas and purchased power to serve retail load. Since price stability is the goal of our system hedge program, financial risks associated with projected requirements of these commodities are systematically hedged at various levels starting approximately three years prior to delivery with standard energy products.

APS has hedged its financial commodity risk since the late 1990's in response to market price fluctuation, with the most recent revisions to the policy in June of 2005, when APS increased its hedge percentages in light of even greater price uncertainty. The measured approach utilized by the system hedge program helps APS customers largely avoid much of the turbulence of price volatility that can occur in the short-term commodity markets. Coupled with the practice of optimizing natural gas and purchased power to provide the lowest cost commodity to meet load, the current approach to hedging financial risk can provide APS customers with future price stability.

I have reviewed the filed testimony of Mr. Antonuk and Mr. Hornby with respect to their assessment of the APS hedging program. With respect to Mr. Antonuk, I concur with the majority of his findings and characterizations as they relate to APS' hedging program. As to Mr. Hornby's testimony, there are a number of statements in his testimony that I believe are incorrect. One such issue is his failure to acknowledge the inherent cost optimization processes found in the APS hedging plan. In addition, Mr. Hornby makes certain general

statements as to the propriety and effectiveness of the APS hedging policy with which I disagree, but on these issues I will defer to the testimony of APS witness Donald Brandt.

III. APS HEDGING PROGRAM AND PHILOSOPHY FOR GAS AND POWER PROCUREMENT

Q. WHAT IS A "HEDGE"?

A. As applied in our industry, a hedge is defined as "any technique designed to reduce or eliminate financial risk." Since commodity prices of natural gas and purchased power are extremely volatile (i.e. can change significantly from day to day), the use of a hedge can eliminate much (but not all) of the financial risk associated with price changes in these markets. From the perspective of APS, we hedge primarily with fixed price contracts, i.e. we fix the price of the commodity for a specific term in order to limit price risk during that term.

Q. HOW LONG HAS APS BEEN HEDGING ITS NATURAL GAS AND PURCHASED POWER NEEDS?

A. APS has hedged natural gas and purchased power requirements for native load customers in various respects since the late 1990's. The impetus for hedging these commodities originated in the increasing exposure to market prices arising from APS' retail load growth and a coincident increase in the volatility of prices in the energy market. The continuing development of organized and relatively liquid commodity markets, and subsequently financial equivalent contracts, has since made the implementation of hedging programs far more efficient and manageable.

Q. HOW WOULD YOU DESCRIBE APS' HEDGING "GOALS" AND HAVE THOSE GOALS BEEN ATTAINED THROUGH THE APS HEDGING PROGRAM?

A. As both Messrs. Antonuk and Hornby correctly state, price stability is the primary goal of the APS system hedge program. Price stability is, of course, a relative concept. In a consistently rising market, even hedged prices will also increase, albeit less quickly. The converse is true in a falling market. APS' system hedging philosophy is not one of trying to predict the direction of the market – as we have said in the past, that's what speculators do, and we do not speculate on behalf of our customers. Our hedging philosophy is mechanistic in its approach with minimal trader discretion as we seek to stabilize costs over time. This goal of price stability is achieved in the current system hedge program by virtue of specific target hedge levels, a requirement for strict compliance in meeting those hedge targets, and senior management oversight and direction of the hedging program.

APS' measured approach to hedging helps its customers largely avoid the turbulence that can occur in volatile short-term energy commodity markets. The peril of failing to properly hedge has severely impacted companies from any number of industries, from utilities to airlines. In our industry, an example of the benefits of a long-term hedge program can be seen in the California energy crisis of 2001 and 2002. Over-reliance on the spot markets for procurement of electricity and natural gas resulted in extreme price volatility. As a result of the implementation of a deregulation plan, the investor-owned utilities in California were restricted from entering into long-term contracts for energy. As spot energy prices increased due to any number of factors, including rising natural gas prices, transmission constraints and limited hydro production, those utilities were forced to buy power from the near-term market. Although they were highly exposed to this market turbulence, neither Pacific Gas & Electric nor Southern

California Edison had a rate mechanism to recover rising costs from their customers. This caused extreme financial distress for the utilities and provided no financial incentive for their customers to curb their consumption of an increasingly expensive commodity. The result was the very well documented "energy crisis" that dramatically impacted both the utilities and their customers.

By hedging purchased power and natural gas needs over a roughly three-year horizon using a systematic approach and well defined compliance deadlines, APS can mitigate the impact of volatile gas and power prices and wholesale capacity concerns for its customers.

Q. CAN YOU PLEASE DESCRIBE THE EVOLUTION OF THE APS HEDGE PROGRAM?

A. In the years prior to 2003, the volumes of natural gas and purchased power exposed to price volatility were considerably less than present volumes and, for the most part, the costs of those commodities were also significantly lower than current costs. As APS' exposure to the requisite volumes of natural gas and/or purchased power increased dramatically, the hedge program followed by APS in the fall of 2003 was restructured to require lower levels of discretion in hedge target levels. Specifically, in the fall of 2003, APS initiated a hedge program for total energy (natural gas and purchased power needs combined) that required near term (or "prompt calendar year") requirements to be 75% hedged prior for that particular year. In June of 2005, APS again modified its system hedge program to address growing concerns about still increasing market volatility and the related financial risks to APS customers. The revised hedge program was prepared in consultation with Risk Advisory, industry experts in the design and implementation of hedging policies and practices, and remains in effect today.

Mr. Antonuk's testimony correctly captures the basics of APS' system hedge program for total energy (again, natural gas and purchased power combined). In summary, APS' hedge program establishes the following requisite hedge levels:

- Remainder of 2006: 85% hedged;
- Calendar Year 2007: 85% hedged;
- Calendar Year 2008: approximately 55% hedged;
- Calendar Year 2009: approximately 35% hedged.

Subsequent calendar year hedge positions are automatically added to the system hedge program as current year positions roll off. For example, APS will begin hedging commodity risk exposure for the first quarter of calendar year 2010 later this year as calendar year 2006 rolls off the plan.

Q. HOW DOES APS ESTIMATE ITS NATIVE LOAD REQUIREMENTS AND THUS ITS REQUIRED HEDGE VOLUMES?

A. APS serves retail load requirements by sourcing power from its nuclear, coal, and natural gas generators, and by purchasing wholesale power in the marketplace under long term agreements, or by purchasing power in shorter term or real-time markets if it is more cost effective than self-generation.

Fuel used in the nuclear and coal-fired generators is purchased through long term contracts at prices that, although escalated over time in accordance with contractual formulae, allow those units to generally run as base load units. Since our retail load demand cannot be readily predicted on an hour by hour or day to day basis, the incremental or "swing" supply of energy needed to serve APS' hourly-varying load is sourced through our natural gas-fired generators, through market purchases of electricity, or through a combination of both.

In attempting to assess future native load energy needs, APS utilizes a computerized simulation model called Real Time Simulation ("RTSIM") to project the necessary level of incremental energy (gas-fired or purchased power, or both). In hedging for the APS system, we use this model to forecast incremental monthly energy needs over a time horizon of roughly three years, in order to establish our hedge requirements. Key inputs into the model include:

- Forecast of system load requirements.
- Forward price curves of natural gas and purchased power.
- Scheduled outages of APS generators.
- Heat rate efficiencies and capacities of APS generators.
- Operating constraints such as Reliability Must Run ("RMR") requirements, minimum run time, ramp rates, etc.

In assessing estimated needs, we are also aware that generators are going to have non-scheduled outages. Because these outages generally occur randomly, APS includes a planning reserve in the monthly supply/demand balance prior to calculating the monthly total energy hedge requirement.

Q. WHAT DOES APS DO TO ATTEMPT TO OPTIMIZE ITS HEDGE POSITIONS?

A. As I will describe in detail later in my testimony, a key area of misunderstanding in the testimony filed by Mr. Hornby involves the cost optimization processes inherent in the APS hedge program. Specifically, in order to allow our hedging program to respond to market price changes on our required hedge volumes, APS re-runs the RTSIM model weekly with updated forward prices for natural gas and purchased power. Under normal situations, the total energy requirements forecast for the forward three years change only minimally, but the least-cost volumetric mix between natural gas and purchased power can vary significantly.

As a result, the traders will "optimize" the hedge position to capture the least expensive incremental energy to serve load, as identified by the model, while adhering to the total energy hedge targets. By optimizing, term traders can:

- Adjust hedge levels of each specific commodity (purchased power versus natural gas).
- Modify receipt and/or delivery points by commodity in order to minimize costs and retain reliability.
- Investigate the economic value of financial/physical derivatives as opposed to outright financial/physical contracts in managing risk.

Notwithstanding such optimizations, the total energy hedge at any given time must remain at the target levels in accordance with the existing system hedge program.

Q. WHAT TYPES OF TOOLS AND/OR CONTRACTS DOES APS USE TO HEDGE ITS NATURAL GAS AND PURCHASED POWER NEEDS?

A. APS transacts in various markets and uses various hedge tools in managing price volatility and financial risk. The most common hedge tools include:

- Physical purchased power contracts delivered at Palo Verde, Four Corners, Mead, and other accessible delivery points.
- Physical purchased power call options to hedge financial capacity risk delivered at Palo Verde, Four Corners, and Mead.
- Financial natural gas futures contracts traded on the New York Mercantile Exchange ("NYMEX"). (The NYMEX financial contracts used to hedge natural gas are very liquid and allow for physical natural gas contracts purchases prior to the delivery month).
- Physical natural gas contracts for gas from the San Juan and Permian Basins.

To give some perspective on the scope of our program, at any one time APS has literally thousands of financial and physical contracts in place covering a roughly three year time horizon.

Q. HOW DOES APS THEN GO FORWARD AND TRANSITION CONTRACTS BOUGHT FOR HEDGES TO DELIVER POWER TO APS' CUSTOMERS?

A. As stated earlier, APS uses a number of mechanisms to hedge its needs. Some are called "physical" contracts (e.g. deliverable power) and others "financial" contracts (e.g. cash settled). The most common "financial contract" is a futures contract. Futures contracts used to hedge our financial risk must be converted to physical contracts in order to obtain the physical commodity to serve load. The most common example of this is the natural gas NYMEX futures contract, which APS uses extensively in hedging.

NYMEX futures contracts expire three business days prior to the first day of the next month. For example, the September 2006 NYMEX natural gas futures contract required as part of our hedging program, expired on August 29, 2006. APS will have then sold all futures contracts back to the market on or just before August 29, and simultaneously purchase a physical supply contract, with a natural gas producer or marketer through an electronic trading platform or via third party brokers, that allows APS to deliver that gas to one of our power plants. In other words, if APS had hedged the equivalent of 5 billion cubic feet (Bcf) of NYMEX natural gas futures for a particular month, APS will sell 5Bcf of futures contracts back to the NYMEX market, and purchase 5Bcf of physical supply through ICE (the Intercontinental Exchange – the most commonly used electronic trading platform in our markets). This activity normally occurs during

the last week of the month prior to delivery, but must occur prior to the expiration of the NYMEX contract.

Within the delivery month, APS will take appropriate short term positions in natural gas and/or purchased power in response to changes in market price or load requirements. These modifications include both the purchase and sale of natural gas and electricity as our native load requires. For example, if APS had expected to burn 100,000 mmbtu of natural gas in our generators on a given day, but because of cooler than normal temperatures, the expected load demand fell, APS will sell back to the market any excess natural gas purchased for that day. The same holds true for any excess purchased power. In the event the load is higher than projected, APS will purchase from the market any additional natural gas or electricity needed to serve that load in the most cost effective manner. Natural gas is normally purchased one day prior to delivery while electricity can be purchased either one day prior or hourly (real time) during the day of delivery.

Q. WHAT ARE SOME OF THE LIMITATIONS ON APS' ABILITY TO HEDGE?

A. Credit restrictions, market liquidity, and load uncertainty are the three primary factors that limit hedging.

- Credit restrictions: Can limit the number of counterparties and hedge tenor (both volume and length of transactions).
- Market liquidity: Reduced liquidity further out in time (2008 and beyond).
- Load uncertainty: Customer demand for electricity changes daily due mostly to weather.

- APS' Credit Score: The strength of APS' credit is critical in allowing APS to transact with favorably-rated counterparties, which in turn limits the amount of credit risk to APS customers.

IV. RESPONSE TO THE FILED TESTIMONY OF WITNESSES ANTONUK AND HORNBY

Q. HAVE YOU READ THE DIRECT TESTIMONY OF STAFF WITNESS JOHN ANTONUK?

A. Yes.

Q. CAN YOU PROVIDE YOUR REACTION TO MR. ANTONUK'S TESTIMONY?

A. As I stated initially, I agree with most of the discussion in Mr. Antonuk's filed testimony regarding APS' hedging program and the implementation of that program. I would also note that, based upon my own observations and numerous discussions with Mr. Antonuk and others from Liberty, I believe Liberty undertook a very thorough audit and review of not only our hedge program, but our trading and hedging practices and procedures.

Q. ARE THERE ANY AREAS WHERE YOU BELIEVE THERE MAY BE SOME FURTHER CLARIFICATION NEEDED REGARDING MR. ANTONUK'S TESTIMONY AND/OR THE LIBERTY AUDIT?

A. Yes. Initially, there are a handful of issues discussed in Mr. Antonuk's testimony that are addressed in the filed testimony of Mr. Brandt. On those issues, I will defer to Mr. Brandt. There are, however, three areas where after reading Mr. Antonuk's testimony, I believe it may be helpful to provide some further discussion and/or underlying factual background.

First, in his testimony, Mr. Antonuk raises the issue of future potential APS costs arising from changes in natural gas pipeline transportation costs. I agree with Mr. Antonuk's conclusion that there has been a substantial shift in the

natural gas transportation pricing structure for APS, with the unwinding (over APS' strenuous objections) by the Federal Energy Regulatory Commission of APS' full requirements agreement with the El Paso Natural Gas pipeline. APS has already begun the process of reviewing alternatives as to future natural gas pipeline transportation alternatives and their associated costs. In fact, APS has discussed many of these options touched upon on this issue by Mr. Antonuk with Staff, (e.g. as discussed below, APS is interested in the development of natural gas storage projects in Arizona, and has received pre-approval from the Commission to contract with Transwestern Pipeline Company, LLC if they indeed expand pipeline infrastructure into the Phoenix market). In any event, I agree with Mr. Antonuk's suggestion and the suggestion found in the Liberty Audit Report that we should meet annually with Staff to provide the results of our analysis of potential cost management options regarding future natural gas pipeline transportation requirements.

Second, both Mr. Antonuk and the Liberty Audit Report raise the issues of natural gas storage and liquefied natural gas ("LNG"). On the gas storage issue, the Liberty Audit Report discusses the need to develop high deliverability natural gas storage to accommodate the operation of combustion turbines. That is one of the reasons why APS remains active in encouraging and assisting in the development of natural gas storage projects that could benefit APS and other natural gas generators (users) in Arizona. APS has worked with a gas storage developer on developing the Red Lake Gas Storage site near Kingman, Arizona. The Red Lake site was a large salt dome structure capable of high gas deliverability ideally suited for power generators. The natural gas storage developer involved in the Red Lake project discontinued this business pursuit

about three years ago, and it is our understanding the storage site has now been sold for purposes of real estate development. In addition, APS has worked with two other gas storage developers over the past two years on developing underground natural gas storage near Eloy, Arizona, at a site commonly referred to as the Picacho site. While this site does not geologically possess the same large salt dome configuration found at Copper Eagle and Red Lake, it appears to have an adequate geological structure to store natural gas that could be used to enhance the overall reliability of supply in Arizona. In summary, APS has a strong interest in securing natural gas storage capacity if indeed a potentially viable geologic site is found and can be allowed to be developed and an appropriate business relationship can be consummated. APS will continue to work with developers to effectuate a mutually beneficial natural gas storage project.

In addition to enhancing the reliability of our natural gas supply through underground gas storage, APS continues to monitor the development of Liquefied Natural Gas ("LNG") at a location just south of Tijuana, Mexico called the Costa Azul LNG project. This facility, which is expected to come on line in 2008, will convert LNG to pipeline quality natural gas with a process called regasification and will be made available to Arizona and California markets immediately by virtue of interstate natural gas pipelines already in place in extreme northern Mexico and the southeast corner of California. APS believes the Yuma area can initially benefit from this new supply of natural gas by virtue of its proximity to the interstate pipeline already in place. Accordingly, again, we agree with Liberty and Mr. Antonuk that the development of LNG should be

monitored closely and may ultimately provide value to Arizona generators, including APS.

Third, the Liberty audit makes a brief reference/recommendation relating to audit procedures for the acceptance of gas supply offers. Based upon my discussions with Mr. Antonuk, I believe this issue relates to APS' level of internal oversight on purchases of our physical gas supply. Specifically, APS generally "rolls" out of its financial hedge position the week prior to the close of the NYMEX contract, during a time period referred to within the industry as "bid week". It is during bid week that buyers/sellers of physical natural gas normally go to the market in order to firm up the next month's physical gas requirements. During this "roll" process, as the physical APS gas trader buys supply in the market, the financial trader generally will sell the financial contracts in order to lock in the appropriate overall value for the supply. While many of those physical trades occur via an online computer system where market values are easily discerned, some occur during normal trading hours directly with gas producers and marketers via telephone solicitations. While existing controls already included the recording of telephone transactions for audit purposes and the review of gas purchase and sale prices by personnel independent of the trading function, APS, following Liberty's suggestion, has expanded the review process to compare its gas transaction prices to market prices through the use of prices captured each hour by an electronic trading platform. Transactions found to fall outside these market parameters are documented by the Compliance Manager and reviewed with the trader and myself and reported to the Energy Risk Management Committee ("ERMC"). In the event the trader has not transacted within the market parameters due to

generally acceptable circumstances (i.e. reliability or system emergencies), the trader will be subject to the terms for trading violations as provided for in the ERMC guidelines.

Q. ONE LAST ISSUE AS TO MR. ANTONUK'S TESTIMONY. HE SUGGESTS THAT THE COMMISSION INTRODUCE AN "INCENTIVE" FOR THE OPTIMIZATION BETWEEN NATURAL GAS AND PURCHASED POWER. DO YOU AGREE?

A. Mr. Antonuk recommends that the Commission introduce a sharing arrangement to provide an incentive for APS to "optimize" between natural gas and purchased power hedge positions. He appears to base this recommendation on his observation that during a period when APS' hedge target was fixed at 85%, the procurement costs were reduced as APS shifted its positions between natural gas and purchased power in response to market price movements. (Antonuk testimony, p 44.) Shifts in hedge positions between natural gas and purchased power are primarily responses to shifting energy need forecasts produced by our RTSIM model as it adjusts its least-cost forecast to changes in market prices (to a lesser degree, such shifts can also be the result of traders managing transaction costs and contract minimum size issues as they try to follow the RTSIM volumetric forecasts). In other words, it is likely that the cost savings that Mr. Antonuk ascribes to optimization in his testimony are due far more to shifts in APS' forecasts and/or specific commodity decisions derived from the RTSIM runs (as described in more detail below) than by adjustments made by the APS traders. Although we appreciate Mr. Antonuk's suggestion on this issue, my belief is that any attempt to optimize beyond the modeling we now employ could create an incentive to try to "outguess" the RTSIM model and approach which we have been able to successfully apply over the last several years.

Q. HAVE YOU READ THE DIRECT TESTIMONY OF RUCO WITNESS J. RICHARD HORNBY?

A. Yes.

Q. CAN YOU PROVIDE YOUR REACTION TO MR. HORNBY'S TESTIMONY?

A. I believe that Mr. Hornby's testimony included a number of statements which were not correct. One example relates to his reference that APS does not optimize under its hedging plan in the context of "minimizing" its overall costs. (Hornby testimony, p. 3)

Q. IN WHAT SENSE DOES MR. HORNBY'S TESTIMONY IGNORE APS' STEPS IN OPTIMIZING ITS HEDGING POSITION AND THE IMPACT THAT PROCESS HAS ON LOWERING COSTS?

A. *In essence, Mr. Hornby's testimony fails to acknowledge the frequent and* continuous re-optimization steps undertaken in conjunction with the hedge program. The primary objective of that re-optimization is cost minimization. As I previously discussed, APS purchases both natural gas and purchased power to hedge our native load requirements. In order to properly quantify the volumes of natural gas and/or purchased power required to meet native load, APS incorporates the aforementioned RTSIM model. The RTSIM model uses software to help determine the optimal commitment and dispatch of APS' generation fleet in light of heat rates, non-fuel O&M, start costs, ramp rates, and so forth, as well as fuel and power prices in wholesale markets. It then forecasts the anticipated requirements for fuel and purchased power. Forecast energy requirements are based on APS' forecast of jurisdictional loads, on the capabilities, operating costs, and maintenance schedules of APS' generation resources, and on forward market prices of natural gas and power.

Since APS can either burn natural gas in its own power generators, or source the wholesale market for available power, the model will take into account the forward cost of each commodity in order to "optimize" the least cost mix of natural gas and purchased power. The model is updated weekly with new forward prices, and traders then use this information to adjust natural gas/purchased power hedge positions in order to reduce the cost to serve retail load. At no time in this process is the overall hedge position compromised. Rather, the model simply provides a report of the most economic mix of natural gas and power for the term of the hedge positions, and the subsequent change in that mix will result in a net lower cost.

Q. ARE THERE ANY OTHER AREAS OF THE FILED TESTIMONY OF MR. HORNBY WITH WHICH YOU DISAGREE?

A. Yes, I disagree with a handful of other assertions in his testimony, including issues relating to the development and overview of APS' hedging philosophy and program, but I defer to Mr. Brandt on these issues.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS incorporates extensive use of financial and physical contracts to minimize commodity price volatility when purchasing natural gas and purchased power to serve native load. Since price stability is the goal of our system hedge program, financial risks associated with projected requirements of these commodities are systematically hedged at various levels starting roughly three years prior to delivery with standard energy products. The measured approach utilized by the system hedge program helps APS customers avoid much of the price volatility that can occur in the short-term commodity markets. Coupled

with the practice of optimizing natural gas or purchased power to provide the necessary commodities to meet load, the current approach to hedging financial risk is providing APS customers future price stability. We appreciate that Mr. Antonuk and Liberty agree with the propriety and soundness of the APS program, and we shall implement their recommendations on our program going forward consistent with the steps outlined in my testimony.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

EXHIBIT
APS 26
Admitted

Arizona Public Service
PSA Adjustor per Gleason Letter
12-Month Rolling Average Fuel Cost

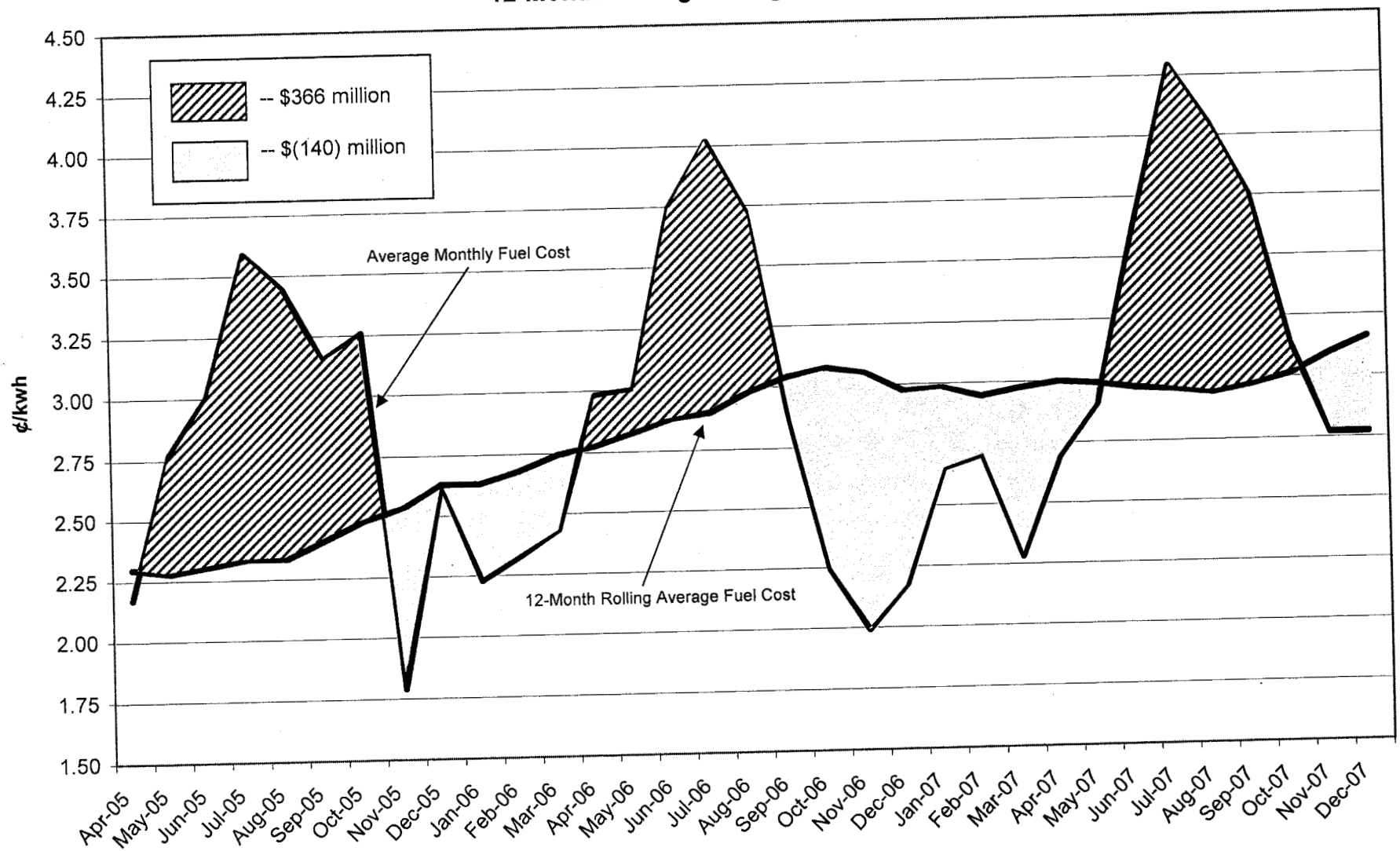

EXHIBIT
APS-27
Admitted

APS Construction Expenditure Projection (as of 08/26/06)

$Millions

Production	2007	2008	2009	2010	2011	5- yr Total
Nuclear (APS Share)						
Nuclear Fuel	42	41	59	55	57	254
Steam Generator, Unit 3	40	1	-	-	-	41
Reactor Vessel Head, Units 1, 2, 3	9	8	13	5	-	35
Water Reclamation Projects - Reservoir & Evap Pond Work	17	12	10	10	5	54
Low-Pressure Turbine Replacement	7	-	-	-	-	7
Other Nuclear Power Plant Improvements - Includes regulatory, safety, reliability, or efficiency projects not listed above	20	21	16	6	6	69
Total Nuclear	**135**	**83**	**98**	**76**	**68**	**460**
Fossil & Hydro (APS Share)						
Cholla Environmental- Includes Baghouse, Scrubber, and other Environmental projects	59	72	57	42	33	264
Four Corners Environmental - Includes NOX abatement, particulate control, and other Environmental projects	10	9	21	34	47	121
Navajo Environmental - Includes NOX abatement and other Environmental projects	-	-	2	2	2	6
Other Coal Plant projects - Includes regulatory, safety, reliability, and efficiency projects at coal plants	44	40	39	44	38	205
Environmental Projects at Gas Plants	2	7	4	7	6	26
Long-Term Service Agreement Costs at Redhawk, West Phoenix	1	1	58	4	2	66
Yuma Peaking Plant	51	15	-	-	-	66
Other Gas Plant projects - Includes capital costs for regulatory, safety, reliability, and efficiency projects at gas plants	15	33	8	5	14	75
Childs / Irving Decomissioning	3	2	2	-	-	7
Total Fossil & Hydro (1)	**185**	**179**	**191**	**138**	**142**	**836**
Total Production	**320**	**262**	**289**	**214**	**210**	**1,296**

APS Construction Expenditure Projection (as of 08/26/06)

$Millions

	2007	2008	2009	2010	2011	5- yr Total
Transmission & Distribution						
Transmission						
Selected Major Transmission Projects						
Palo Verde - TS5 (TS5 to be located northwest of White Tanks)	8	40	45	-	-	93
TS5 - TS9 (TS9 to be located near existing Raceway substation)	-	-	-	28	61	89
TS5 - TS1 (TS1 to be located southwest of 195th Av & Deer Valley)	10	14	12	-	-	36
TS1 - Palm Valley	10	-	14	13	-	37
TS9 - Pinnacle Peak 500kV	6	45	36	26	-	113
Palo Verde - North Gila 500kV	-	5	9	37	42	93
All Other Transmission Infrastructure Additions & Upgrades - includes Line & Substation additions & upgrades for 69kV and above voltage not listed above	114	94	137	49	72	466
Transmission Reliability Projects - Includes Breaker, Capacitor, and Reactor projects; Homeland Security-related spare transformers & breakers; and other major reliability projects	21	19	25	24	34	123
Transmission relocations & emergency projects	5	5	5	5	5	25
Total Transmission (2)	**174**	**222**	**283**	**182**	**214**	**1,075**
Distribution						
Distribution Infrastructure projects - includes Line & Substations additions & upgrades	80	63	58	59	63	323
Distribution Reliability Projects - includes projects for substation, overhead, and underground equipment	38	39	45	47	49	218
Other Distribution Projects - Safety, Relocation / Conversion, Emergency, and other projects	20	20	25	26	29	120
New Customer Construction						-
Meters	26	25	25	25	25	126
Transformers	34	33	32	31	28	158
Service & Line Extensions	118	123	128	134	135	638
Street Light / Dusk-to-Dawn	4	4	4	4	4	20
Total Distribution	**320**	**307**	**317**	**326**	**333**	**1,603**
Total Transmission & Distribution	**494**	**529**	**600**	**508**	**547**	**2,678**
General Plant						
Customer Service information systems	6	15	14	7	5	47
Distribution operations & work-management systems	11	9	12	11	10	53
Material Logistics Information System	-	-	1	25	19	45
All Other Info Sys Projects - includes infrastructure additions, equipment replacement, and all other Generation, T&D, and Shared Services systems & telecom	32	51	54	42	41	220
Facilities - includes new service centers, upgrades of existing facilities, and replacements of mechanical equipment, plumbing, etc. at APS facilities.	31	57	51	36	42	217
Other General Plant	2	1	2	2	2	9
Total General Plant	**82**	**133**	**134**	**123**	**119**	**591**
Total APS	**896**	**924**	**1,023**	**845**	**876**	**4,565**

(1) Assumes no self-build costs for new generation projects other than Yuma peaking plant.

(2) Excludes costs for TransWest Express and other new transmission projects associated with new resource acquisitions.

Arizona Public Service Company
CONSTRUCTION WORK IN PROGRESS
As of June 30, 2006

EXHIBIT
APS-28
Admitted

Line No.			
1.	Generation	$	91,655,930
2.	Distribution		117,664,651
3.	General & Intangible		39,192,545
4.	Nuclear Fuel		12,101,088
5.	Sub Total	$	260,614,214
6.	Transmission		63,360,648
7.	Total APS	$	323,974,862

ARIZONA PUBLIC SERVICE COMPANY
Generation CWIP with Description
As of June 30, 2006

Line No.	Description	Location	Total
1.	STEAM GENERATOR 3RD SET	PV 3	$ 20,699,938
2.	WRF RESOVOIR POND LINER	PV WATER REC FACILITY	10,427,962
3.	FABRIC FILTER INSTALLATION, U1	CHOLLA 1	8,102,217
4.	STEAM GENERATOR U3 INSTALLATION	PV 3	6,520,207
5.	STEAM GENERATOR: LP TURBINE ROTORS REPL U3	PV 3	4,784,831
6.	CT1A GE LTSA LARGE PARTS	REDHAWK 1	4,427,781
7.	CT1B GE LTSA LARGE PARTS	REDHAWK 1	4,427,781
8.	CC5 WESTINGHOUSE 5B GAS TURB LTPM	WEST PHX CC5	3,620,093
9.	GENERATOR ROTOR REPL, 4/C 2	FC 1	3,437,976
10.	CPC/CEAC REPLACEMENT U3	PV 3	2,325,454
11.	U1-3 LIME FEED IMPROVEMENT	FC 1	2,088,804
12.	WRSS PIPELINE PHASE II	PV WATER REC FACILITY	1,872,077
13.	5248 FT LL ASH IMPOUND FC1-3	FC 1	1,836,725
14.	LAKE PUMP INTAKE RELOCATION PROJ	NAVAJO	1,585,360
15.	MAIN GEN ROTOR CAP SPARE	PV-COMMON	1,334,255
16.	U1 GENERATOR STEP UP TRANSFORMER T535 REPL	CHOLLA 1	1,197,519
17.	U1 HP IP TURBINE REPL	CHOLLA 1	974,498
18.	REACTOR VESSEL HEAD REPL. U3	PV 3	954,162
19.	BRINE SOLIDS DRYING AREA UPGDE	REDHAWK COMMON	935,137
20.	U1-3 COAL HANDLING IMPROVEMENTS	CHOLLA 1	934,362
21.	COOLING TOWER LIFE EXT PHS IV	PV 1	862,146
22.	FUEL HANDLING SYSTEM MOD	PV 2	817,818
23.	U3 HP/IP/LP TURBINE REPL	CHOLLA 3	728,203
24.	CONTAINMENT SUMP SCREEN REPL U2	PV 2	686,727
25.	FOUR CORNERS: C/O (7) 345KV BREAKERS	F/C SWITCHYARD	646,471
26.	COOLING TWR LIFE EXT PHASE IV	PV 2	626,269
27.	U2 CIRC WATER PIPE REPLACE PHASE II	PV 2	532,968
28.	CT3 SPEEDTRONICS UPGRADE	YUCCA CT 1	509,149
29.		**GENERATION >$500K**	**87,896,890**
30.		**GENERATION < $500K**	**3,759,039**
31.		**TOTAL GENERATION**	**$ 91,655,930**

ARIZONA PUBLIC SERVICE COMPANY
Distribution CWIP with Description
As of June 30, 2006

Line No.	Description	Total
1.	SCHEMATIC SOFTWARE	$ 9,373,858
2.	HARDWARE - DOMS INFRASTRUCTURE 2005-2006	3,489,072
3.	EMS UPGRADE II - HARDWARE	2,974,385
4.	EMS UPGRADE III - SOFTWARE	2,715,832
5.	EMS PROJECT - SOFTWARE	2,505,014
6.	SOFTWARE - AUTOMATIC METERING SYSTEM	1,853,000
7.	EMS UPGRADE II - SOFTWARE	1,551,329
8.	MOBILE DATA INFRASTRUCTURE - 2005	1,509,329
9.	LRT-LS4/32 ST TO 34 ST CONVERSION	1,408,570
10.	HATFIELD/NEW SUB/103 AV & HATFIELD	1,322,932
11.	GREY BEARS SUB - SITE PREP FOR NEW	1,200,635
12.	HOHOKAM SUB - BUILD NEW SUBSTATION	1,145,577
13.	GREY BEARS SUB - BUILD NEW SUBSTATION	1,123,734
14.	PEBBLECREEK SUB - SITE PREP FOR NEW	1,073,097
15.	TALKING ROCK RANCH 12KV UG FDR EXIT	1,039,882
16.	DOMS INFRASTRUCTURE 2005-2006 -SOFTWARE	1,039,152
17.	P1D METERS	1,012,622
18.	MOBILE DOMS -SOFTWARE	993,942
19.	OCOTILLO NEW SC (A. GREELEY)	909,289
20.	MARINETTE TAP - MARINETTE 69KV REBUILD	894,209
21.	RELOCATE OH TO U/G CONVERSION/12 KV	791,823
22.	REPUBLIC PLASTICS PLANT, COMEX RD	785,686
23.	ORANGEWOOD SUB 12KV/OH-UG CONVERSION	785,086
24.	B I/23 ST & WASHINGTON/ADD NEW FEEDER	768,654
25.	UP FRONT JOB DESIGN IMPLEMENTATION	735,035
26.	VERRADO 2W WESTERN DR INF.	713,186
27.	"VILLAGO" SUBDIVISION	673,420
28.	BLUE RIDGE SUB - BUILD NEW SUBSTATION	617,382
29.	ENERGY ACCOUNTING SYSTEM REPORTING BILLING SYSTEM	605,471
30.	EPRI RELATED - MAINTENANCE OPTIMIZATION THROUGH PROCESS AND TECHNOLOGY - SOFTWARE	602,994
31.	SA SR 179 ROAD WIDENING PH 1 VOC	589,844
32.	PINNACLE PARK -PHASE 1A- 1125 W PINNACLE PEAK RD	572,749
33.	FESTIVAL RANCH PH 2 INFRASTRUCTURE	572,489
34.	HEARN SUB - SITE PREP FOR NEW SUB	553,481
35.	WINDGATE RANCH - TPP FEEDER	514,116
36.	CAMMS - TWO WAY RADIOS - HARDWARE	507,738
37.	**DISTRIBUTION > $500K**	**49,524,614**
38.	**DISTRIBUTION < $500K**	**68,140,037**
39.	**TOTAL DISTRIBUTION**	**$ 117,664,651**

ARIZONA PUBLIC SERVICE COMPANY
General & Intangible CWIP with Description
As of June 30, 2006

Line No.	Description	Total
1.	IBOS TECHNOLOGY (HARDWARE)	$ 9,632,933
2.	IBOS GL/AP/AR/BUDGET	7,029,272
3.	IBOS SCM PHASE 1 - MLIS WRAPPER	4,747,429
4.	IBOS PURCHASED SOFTWARE	4,533,521
5.	EMS RTU COMMUNICATIONS - DUAL HOME	3,796,189
6.	SOFTWARE - ENTERPRISE APPLICATION INTEGRATION INFRASTRUCTURE IMPLEMENTATION	3,727,714
7.	IDENTITY MGMT - SOFTWARE	1,352,027
8.	BCCP2 TENANT IMPROVEMENT MASTER WO	979,623
9.	BIODIESEL ADAPTATION MODULE	698,341
10.	NETWORK STORAGE 2006/06 - HARDWARE	613,261
11.	NETWORK STORAGE 2005/06 - SOFTWARE	604,147
12.	EXCHANGE SVR 2003 IMPLEMENTATION - HARDWARE	579,814
13.	IS BUSINESS CONTINUITY - HARDWARE	568,388
14.	**GENERAL & INTANGIBLE > $500K**	**38,862,660**
15.	**GENERAL & INTANGIBLE < $500K**	**329,884**
16.	**TOTAL GENERAL & INTANGIBLE**	**$ 39,192,545**

EXHIBIT
APS-29
Admitted

DIRECT TESTIMONY OF STEPHEN J. BISCHOFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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I. Introduction 1

II. Bark Beetle Infestation Remediation. 3

III. Conclusion 9

Map of Bark Beetle Infestation ..... Attachment SJB-1

Bark Beetle Work Activity and Expenses ..... Attachment SJB-2

DIRECT TESTIMONY OF STEPHEN J. BISCHOFF
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Stephen J. Bischoff. My business address is 2121 W. Cheryl Drive, Phoenix, Arizona 85021.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the General Manager of Construction, Operations and Maintenance for Arizona Public Service Company ("APS" or "Company"). My responsibilities include the statewide maintenance of the transmission system and all APS substations, and the operations and maintenance of the distribution system in the Greater Phoenix metropolitan area. I also am responsible for the planning of the sub-transmission (69 kV) and distribution electric infrastructure needs for the Company.

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Arizona. During the summers while attending the college, I worked at Southern California Edison Company in the Los Angeles area. Upon graduation, I went to work for APS and have been employed with the Company for more than 32 years. I have worked in various Engineering and Operations roles, including transmission and distribution construction, design, maintenance, and operations. I also have worked as the Manager of the Commercial &

Industrial ("C&I") Marketing department, assisting our C&I customers in evaluating various end-use technologies, including self-generation.

I am a Registered Professional Electrical Engineer in the State of Arizona. Further, I am a member of the Institute of Electrical and Electronics Engineers ("IEEE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will address the actions taken by the Company to respond to damage caused by bark beetle infestation.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS has implemented an extensive program to address the threat posed to our transmission and distribution system by the bark beetle infestation. In Decision No. 67744 (April 7, 2005), the Arizona Corporation Commission ("Commission") authorized APS to defer the reasonable and prudent costs of those efforts incurred beginning in 2005 that exceed 2002 test year levels of tree and brush control. The Commission also indicated that in the next APS rate case, it would determine the reasonableness, prudence and appropriate allocation between distribution and transmission of these costs.

Although APS already has completed an extensive amount of remediation relating to the bark beetle infestation, there is still much to do. We will need to continue to patrol lines and remove trees along the approximately 1600 miles of distribution lines and 500 miles of transmission lines that are crossing the impacted forest areas. Our current estimate is that we will spend in excess of $11 million during the two (2) year period from 2005 through 2006 clearing our distribution lines, and approximately $1.7 million for transmission lines. It is

important to recognize that our plans in 2006 and beyond are subject to change, based on weather conditions and the infestation rate. We will continue to monitor these conditions and adjust our plans in this timeframe as warranted. APS witness Laura Rockenberger is sponsoring the pro forma adjustment to the test year for the amortization of this increased cost for 2005-2006.

II. BARK BEETLE INFESTATION REMEDIATION

Q. PLEASE BEGIN BY EXPLAINING WHAT APS' FORESTRY DEPARTMENT DOES.

A. The APS Forestry and Special Programs Department ("Forestry Department") is responsible for managing the Company's line-clearance vegetation management, landscaping, pole inspection, and wildlife protection programs throughout Arizona. APS has a staff of six arboricultural professionals, including both degreed Foresters and Arborists, who direct these programs. The department provides services throughout the state of Arizona, with offices located in Phoenix, Prescott, Yuma, Cottonwood, Payson, Show Low and Flagstaff.

The Forestry Department focuses on maintaining an extremely high-quality field operation. To that end, all crew operations are performed in accordance with ANSI A-300 Standards for Tree Care and ANSI Z133.1 Arboricultural Operations Safety Requirements. All supervisors and crew leaders are required to earn and maintain certification as International Society of Arboriculture ("ISA") Certified Arborists. Crewmembers are required to earn and maintain certification as ISA Tree Workers, and APS provides extensive ongoing arboricultural training. Obtaining ISA certifications requires both independent study and significant field experience. Maintaining these certifications requires earning a minimum of ten hours of continuing education credits annually.

The high-quality standards of the Forestry Department have been nationally recognized. APS has been designated a Tree Line USA® Utility for the past nine years. The Tree Line USA® program, which is sponsored by The National Arbor Day Foundation in cooperation with the National Association of State Foresters, recognizes utilities that demonstrate practices that protect and enhance America's urban forests. This coveted distinction has been earned as a direct result of administering a superior program of professional tree care, providing annual worker training, and implementing tree planting and public education programs related to proper tree care.

Q. HOW DOES APS DETERMINE THE ACTIONS IT WILL TAKE TO ADDRESS RISKS TO ITS TRANSMISSION AND DISTRIBUTION LINES FROM TREES?

A. APS' normal maintenance program is set based on the follow factors:

- the tree species, including its branching habit, wood strength, growth and regrowth rates;
- the location of the tree in relation to the conductors;
- the voltage of the conductors and type of construction;
- environmental conditions, including the extent of irrigation and soil conditions; and
- the length of the pruning cycle.

The cycle length depends on the factors listed above. The general rule of thumb, however, is that the Company performs line clearance work in urban areas every 2 years and in rural areas every 5 years. The shorter cycle time in urban areas is a result primarily of the types of trees the Company finds along its transmission and distribution lines in those areas. In urban areas, those trees tend to be faster

growing due to the planting of tall growing trees and the availability and use of additional irrigation.

Q. HAS APS EXPERIENCED ANY INCREASED COSTS FOR ITS FORESTRY PROGRAMS OVER THE LAST FEW YEARS?

A. Yes, we have, both generally and because of the bark beetle infestation. The ongoing O&M expenses, without considering the added burden of the bark beetle infestation, have increased due to a number of factors, including the following:

- Increased federal regulatory requirements, including compliance with the National Environmental Policy Act ("NEPA"). Under NEPA, the Company must conduct biological assessments and surveys for threatened and endangered species, archeological assessments, and tree inventories before we can remove or prune trees.
- Compliance with more stringent NERC Transmission Vegetation Management Standard requirements, such as increased documentation.
- Continued increase in need to mitigate fire risk through brush clearing around wood pole structures.
- Vehicle maintenance costs.
- Salary increases to retain qualified employees.

Q. PLEASE SUMMARIZE THE BARK BEETLE INFESTATION IMPACTS ON ARIZONA AND APS?

A. During the extended drought that Arizona experienced over much of the past decade, the Ponderosa pine forest trees were weakened to the extent that they became susceptible to infestation by bark beetles. Based on a 2003 statistical analysis performed by ecosystem scientists from the University of California at Berkley and an independent utility vegetation management consulting group, it

was estimated that approximately 748,600 dead or dying trees caused by this infestation would be within falling distance of our power lines. Attachment SJB-1 is a map showing the areas of the state impacted by the bark beetle infestation overlaid on the APS service territory.

Q. WHAT HAS APS DONE TO DATE WITH RESPECT TO BARK BEETLE REMEDIATION?

A. Initial study data indicated that 31 percent of trees infested by bark beetles would fall within four years after death. This meant that the trees near our power lines would need to be removed over a three to five year period to both protect the transmission and distribution system and to avoid the possibility of causing devastating forest fires. Based on historical data for the anticipated type of tree removal, an average cost of $45 per tree was used to develop an initial project cost estimate of nearly $33,690,000.

Subsequent to the preparation of the initial study, however, the mortality rate of the trees changed and fewer trees had to be removed than originally expected from each area affected by the infestation. Thus, the original plan to go through the rights of way one time to perform all tree removals at once was not feasible. Rather, the Company now performs quarterly patrols of all areas impacted by the bark beetle infestation and identifies individual trees for removal. APS may remove trees several times each year along the same segments of power lines, depending on how the trees are doing. This modified approach to removing dead or dying trees, which preserves those trees not affected, has resulted in an increase in the actual cost per tree removed. APS already has incurred significant costs to remove dead or dying trees from around its transmission and distribution system. APS spent approximately $2.3 million in 2003, $6.7 million

in 2004, and over $5.1 million from January through November of 2005 to address the infestation on the APS distribution system alone. [See Attachment SJB-2.]

Q. WHAT DOES APS DO WITH THE TREES THAT IT REMOVES?

A. APS has reached agreements with the United States Forest Service ("USFS") that contain specific requirements depending on which National Forest is involved. Generally, however, those agreements require APS to place the trees in slash piles and leave them for the USFS, which often burns them in place. On private lands, however, APS typically cuts down the trees, chips the branches, and leaves the logs on site.

Q. WHAT WORK DOES APS HAVE LEFT TO COMPLETE FOR BARK BEETLE REMEDIATION?

A. As of November 2005, we have removed nearly 187,000 damaged and threatening trees along our distribution lines. We will need to continue to remove additional trees until the infestation has slowed to a normal pace. As noted previously, the actual number of trees that we will need to remove will be determined as the impact of the infestation progresses.

Q. HOW MUCH DOES APS ANTICIPATE IT WILL COST TO COMPLETE THOSE ACTIVITIES?

A. We estimate that to address the remaining trees that will need to be removed from our distribution lines due to bark beetle damage, we will spend about $11,300,000 over the two-year period from 2005 through 2006. [See Attachment SJB-2.] At this point, it is unknown if the infestation will continue beyond 2006, and whether any additional funds will be expended beyond 2006. It is expected that the cost per tree will increase, however, because the mortality rate is

declining, which means that the remaining infested trees are in scattered pockets instead of in large, consolidated areas of infestation. Thus, it takes additional time and expense to travel to these locations.

Q. DID THE COMPANY TAKE ANY STEPS TO SEEK FEDERAL FUNDING FOR THESE COSTS?

A. Yes, we did. I would quickly add that the Commission, the Governor, and others also sought such funding. Specifically, Commissioner Mayes wrote the Regional Forester in Albuquerque, New Mexico, expressing her position that the costs associated with keeping the federal forests healthy should be borne by the federal government, not the state of Arizona or utility customers. Governor Napolitano declared a state of emergency in our forests and twice requested federal funds to address the emergency. Both requests were denied. The Forest Health Oversight Committee, established by the Governor to address the overall health of the forests, developed a recommendation that would make federal funds available now, before a catastrophic fire occurs. In addition to actively participating on the Forest Health Oversight Committee, the Company met several times with state and federal organizations to discuss availability of funding. The Healthy Forest bill passed Congress and was signed by President Bush, but no funding was provided for implementation of the bill. Therefore, Arizona has no federal funding for the bark beetle problem.

Q. WHAT RATEMAKING TREATMENT IS THE COMPANY PROPOSING RELATED TO THESE REMEDIATION EXPENSES?

A. The Company expects to spend approximately $11.3 million dollars on bark beetle remediation from January 1, 2005 to January 1, 2007, when it is anticipated that the rates from this filing will be in place to recover these costs.

The Company is proposing to recover these costs through base rates over three years. Ms. Rockenberger discusses the pro forma adjustment for these costs.

Q. WHAT IF THE COMPANY EVENTUALLY RECEIVES GOVERNMENT FUNDING REIMBURSING APS FOR THE COSTS IT HAS OR WILL INCUR?

A. Although that appears highly unlikely at this point, if the Company eventually receives government funding to mitigate this expense, APS would credit it back to customers in the next rate case.

III. CONCLUSION

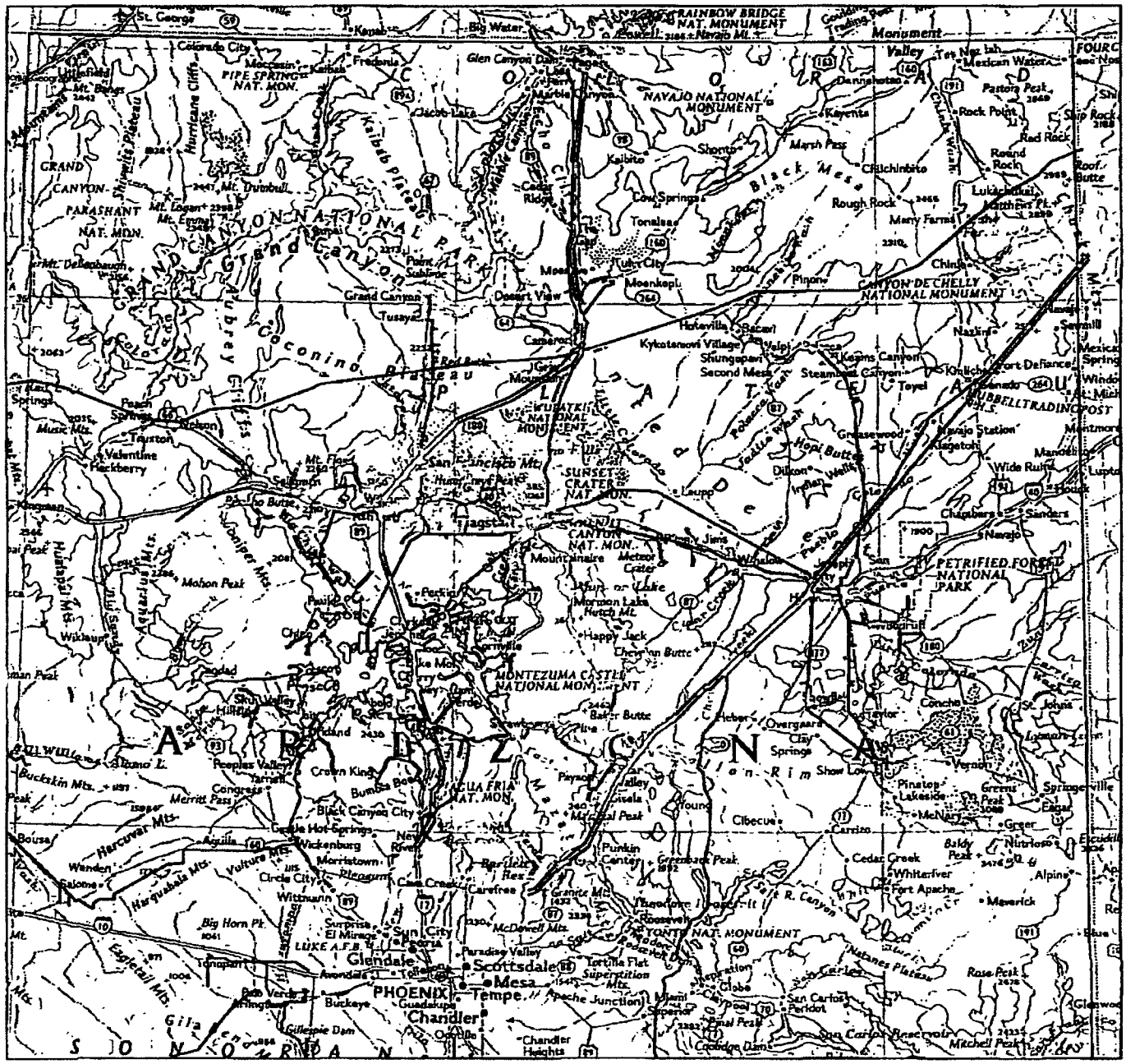
Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The Company has incurred and will continue to incur costs for the remediation required by the bark beetle infestation that has affected a large part of the State. Because those activities are critical to protecting our system and reducing the threat of catastrophic forest fires, the Company should recover those costs.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Beetle Work 2003 Through August 2005


Grand Canyon
Flagstaff
Sedona
Cottonwood
Prescott
Kingman
Lake Havasu City
Parker
Yuma
Bullhead City
Page
Tuba City
Kayenta
Chinle
Holbrook
Show Low
Pinetop
Lakeside
Greer
Springerville
Eagar
Alpine
Globe
Miami
Superior
Payson
Camp Verde
Cottonwood
Cornville
Clarkdale
Jerome
Cave Creek
Carefree
Fountain Hills
Tonopah
Buckeye
Avondale
Goodyear
Litchfield Park
Tolleson
Wickenburg
Congress
Yarnell
Prescott Valley
Chino Valley
Paulden
Seligman
Peach Springs
Valentine
Hackberry
Kingman
Oatman
Bullhead City
Mohave Valley
Fort Mohave
Needles
Topock
Parker
Quartzsite
Ehrenberg
Bouse
Salome
Wenden
Aguila
Morristown
Wittmann
Surprise
El Mirage
Peoria
Glendale
Scottsdale
Mesa
Tempe
PHOENIX
Chandler
Gilbert
Queen Creek
Superior
Miami
Globe
Hayden
Winkelman
San Carlos
Peridot
Fort Apache
Whiteriver
Cedar Creek
Carrizo
Cibecue
Overgaard
Clay Springs
Heber
Pinetop
Lakeside
Greens Peak
McNary
Vernon
Concho
St. Johns
Springerville
Eagar
Alpine
Maverick
Rose Peak
Mitchell Peak
Chandler Heights
Apache Junction
Superstition Mts.
Tortilla Flat
Paradise Valley
Scottsdale
Tempe
Mesa
Gilbert
Chandler
Ocotillo
Guadalupe
Buckeye
Tolleson
Litchfield Park
Avondale
Goodyear
Tonopah

ARIZONA PUBLIC SERVICE COMPANY
BARK BEETLE WORKSHEET
WORK ACTIVITY AND EXPENSES
(2003 - 2006)

DISTRIBUTION

YEAR	2003	2004	2005		2006
			Jan. - Nov.	Projected - Y.E.	Projected Y.E.
Trees Worked	50,181	90,321	46,420		
Total Cost	$2,345,584	$6,699,079	$5,173,879	$5,644,232	$5,644,232
Cost / Tree	$46.74	$74.17	$111.46		

TRANSMISSION

YEAR	2003	2004	2005		2006
			Jan. - Nov.	Projected - Y.E.	Projected Y.E.
Trees Worked	221	35,473	5,351		
Total Cost	$34,227	$715,908	$799,406	$872,079	$872,079
Cost / Tree	$154.87	$20.18	$149.39		

TOTAL T&D

YEAR	2003	2004	2005		2006
			Jan. - Nov.	Projected - Y.E.	Projected Y.E.
Trees Worked	50,402	125,794	51,771		
Total Cost	$2,379,811	$7,414,987	$5,973,285	$6,516,311	$6,516,311
Cost / Tree	$47.22	$58.95	$115.38		

EXHIBIT

APS-30

Admitted

REBUTTAL TESTIMONY OF STEPHEN J. BISCHOFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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I. Introduction 1

II. Summary of Rebuttal Testimony 1

III. Bark Beetle Infestation Remediation Costs 2

IV. Reliability 5

V. Distributed Generation Workshop Activities 11

VI. Conclusion 13

Bark Beetle Work Activity & Expenses ..... Attachment SJB-1RB

REBUTTAL TESTIMONY OF STEPHEN J. BISCHOFF
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Stephen J. Bischoff. My business address is 2121 West Cheryl Drive, Phoenix, Arizona 85021.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the testimony of various Commission Staff and intervenor witnesses related to expenditures and deferral of costs related to bark beetle remediation as well as concerns regarding electricity outages and reliability. My rebuttal testimony will also address concerns raised by William J. Murphy on behalf of the Arizona Cogeneration Association/Distributed Energy Association of Arizona ("DEAA") and Edward Smeloff on behalf of Solar Advocates that deal with distributed generation interconnection requirements.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony will explain why the level of reasonable and prudent bark beetle remediation costs has been modified from that discussed in my Direct Testimony. Specifically, the modifications were necessary to reflect the way such costs are recorded in the General Ledger by FERC account. In addition, costs and credits were inadvertently excluded in the original submission. The net result of

these modifications increases the previous level of deferred costs by less than three percent. In addition, I address concerns raised by Staff associated with reliability issues and discuss the status of projects implemented to deal with the reliability concerns. Finally, I describe APS' participation in the ongoing distributive generation workshops conducted by the Commission and my position that the concerns raised by Solar Advocates and DEAA regarding distributed generation interconnection requirements be dealt with through those workshops.

III. BARK BEETLE INFESTATION REMEDIATION

Q. STAFF CONSULTANT UTILITECH INC. IS RECOMMENDING A PARTIAL DISALLOWANCE OF BARK BEETLE REMEDIATION COSTS INCURRED BETWEEN JANUARY 1, 2005 AND MARCH 31, 2005, PRIOR TO THE EFFECTIVE DATE OF DECISION NO. 67744. DO YOU AGREE?

A. As explained in the testimony of Laura Rockenberger, it is APS' position that Decision No. 67744 authorized the recovery of Bark Beetle Remediation Costs from the years 2005 forward. Staff's proposed disallowance is based upon the timing of when costs were incurred and not a determination that the costs were imprudent or unreasonable.

Q. WHAT WERE THE TOTAL COSTS DEFERRED FROM JANUARY 2003 TO DATE, FOR BARK BEETLE INFESTATION REMEDIATION?

A. No bark beetle costs were deferred in the years 2003 and 2004. All distribution bark beetle costs for the years 2005 and 2006 were deferred pursuant to Decision No. 67744. Approximately, $6,283,000 was deferred for the year 2005, and $5,339,000 will be deferred for the year 2006. Deferrals for bark beetle expense were recorded once adjustments were made to ensure that expenses for distribution line vegetation management in 2005 and 2006 would equal the level of such expenses in the 2002 Test Year, as specified by Decision No. 67744.

Q. WHAT IS THE LEVEL OF DEFERRED EXPENSE THROUGH 2006 FOR BARK BEETLE REMEDIATION FOR THE YEARS 2005 AND 2006?

A. APS estimates it should recover approximately $11,622,000 for deferred bark beetle remediation costs from January 1, 2005 through January 1, 2007.

Q. IN YOUR WORK PAPER SJB_WP3, THERE IS A LINE ITEM ENTITLED, "TOTAL BARK BEETLE." DEFINE THE COSTS WHICH ARE INCLUDED IN THAT LINE ITEM.

A. The type of costs that are included in the subject line item reflect expenses paid to remove and/or clear dead or dying trees from proximity to our distribution lines on forested lands. These trees would otherwise represent a hazard to the reliability of the system and could result in forest fires if contact with the lines were made. These costs include payroll and benefits, transportation, material and supplies, employee expenses, outside services, and other types of expenses related to this work.

Q. IN YOUR WORK PAPER SJB_WP3, PLEASE EXPLAIN THE CHARGES ENTITLED "OTHER O&M" TO THE DISTRIBUTION AND TRANSMISSION LINES.

A. The charges identified as "Other O&M" are those charges, including payroll, materials and supplies, and other related costs that were charged for tree and brush control costs that were not charged to a specific work order identified as "bark beetle."

Q. HAVE YOU MODIFIED THE COSTS ASSOCIATED WITH BARK BEETLE INFESTATION FROM YOUR ORIGINAL TESTIMONY?

A. Yes.

Q. WHY WERE THE COSTS MODIFIED FROM THE ORIGINAL FILING?

A. Bark beetle costs have been modified from earlier testimony to reflect the way they are recorded in the General Ledger by FERC account. The costs as originally

presented separated transmission and distribution work by the primary functions of the departments performing the work. However, this did not address the issue of transmission department personnel occasionally doing work on the distribution system, or visa-versa. Since these groups charge their time to specific job numbers, they are correctly recorded in the General Ledger as Transmission or Distribution based on the job worked on, rather than by the department's primary function. Further, certain costs and credits were inadvertently excluded in the original submission.

Q. COULD YOU PLEASE EXPLAIN WHAT TYPES OF MODIFICATIONS WERE MADE?

A. Attachment SJB-2 to my direct testimony provided total distribution and transmission costs for the year 2004 in the amounts of $6,699,079 and $715,908 respectively. Upon modification of the 2004 costs described above, the distribution cost for 2004 were revised from $6,699,079 to $6,617,978. The cost per tree under the distribution category has also been revised from $74.17 to $73.27. In addition, modifications were made to the transmission cost from $715,908 to $785,606. The cost per tree under the transmission category has also been revised from $20.18 to $22.15. The combined per tree cost for transmission and distribution in 2004 decreased from $58.95 to $58.85.

Q. ARE THERE OTHER MODIFICATIONS TO ATTACHMENT SJB-2?

A. Yes. Attachment SJB-2 to my direct testimony calculated 2005 costs using actual data from January through November and projected costs for December of 2005. We have updated the 2005 costs to include actual costs incurred through December of 2005. By updating the 2005 costs, distribution costs increased from $5,644,232 to $6,282,819. Transmission costs increased from $872,079 to

$1,104,227. We have also included the actual January through July 2006 expenses for bark beetles and projected a year end 2006 figure. This update changed the year end 2006 projection from $5,644,232 to approximately $5,339,000 for distribution only. The corresponding costs per tree figures are also updated.

Q. BASED UPON THE ABOVE CHANGES, WERE OTHER MODIFICATIONS NECESSARY TO YOUR ORIGINAL FILING?

A. Yes. To support these modifications, I have attached (as Attachment SJB-1RB) a revised Attachment SJB-2 from my direct testimony and have provided revised versions of work papers SJB_WP3 and SJB_WP4.

Q. IS APS REVISING ITS REQUEST FOR RECOVERY OF BARK BEETLE COSTS IN THIS APPLICATION?

A. Only to the extent that the actual costs for December of 2005 and a revised projected year end 2006 have been modified. The above changes for the year 2004 will not effect APS' proposal because Decision No. 67744 only authorized recovery of reasonable and prudent costs beginning in 2005. APS witness Laura Rockenberger has revised the pro forma adjustment to the test year for the amortization of this increase.

IV. RELIABILITY

Q. STAFF'S ENGINEERING DEPARTMENT, IN ITS ASSESSMENT OF THE QUALITY OF SERVICE PROVIDED BY APS TO ITS CUSTOMERS, DETERMINED THAT THERE WAS NO REASON TO RECOMMEND CONSIDERATION OF QUALITY OF SERVICE MITIGATION MEASURES AS PART OF THE PENDING APS RATE CASE. IN IT'S QUALITY OF SERVICE ASSESSMENT AND USED AND USEFULL DETERMINATION, DID STAFF IDENTIFY SEVEN ITEMS ASSOCIATED WITH 2005 TEST YEAR CAPITAL IMPROVEMENTS THAT "MERIT SOME ATTENTION" AND WHAT STEPS HAS APS TAKEN TO RESOLVE THESE ISSUES?

A. Yes, Staff did identify the following seven items that merit some attention as follows:

1) "Chino Wells Substation is an old substation with old equipment serving water pumps for Chino Wells. The station service transformers are not in service and have been abandoned in place. The substation transformers are old and showed signs of old oil leaks and have older Type U bushings. The substation is scheduled for replacement or refurbishment in the next few years."[1]

Status: As noted, APS is currently in discussion with the City of Prescott regarding an expansion of the well field. At that time, the substation will be rebuilt to accommodate the increased demand. APS will continue to monitor the equipment in the substation to ensure reliable service. The station power transformers no longer in service have been removed.

2) "The Fairview generator and an emergency 69kV tie at Sulphur Springs Valley Electric Cooperative's ("SSVEC") McNeal Substation are of inadequate capacity to restore full service to all of the Southeast Division for an outage of the APS Adams to Mural 115 kV line. This service area has the potential of exhibiting quality of service concerns comparable to that of Nogales and Santa Cruz County. In fact, the Southeast Division is APS' poorest service performance division over the last five years. A second 69 kV tie is being sought with SSVEC."[2]

Status: The local generation and the emergency tie through SSVEC's McNeal substation is not currently adequate to restore full service to all customers in

[1] See Engineering Report: Staff's Quality of Service Assessment and Used and Useful Determination, dated August 18, 2006, pp 7-8

[2] *Id.*

APS' Cochise District. However, this limitation is abnormal and only temporary because it is caused by two defective transformers at Southwest Transmission Cooperative's (STC) Apache substation and is expected to be remedied by the end of the year. As designed, the emergency tie and local generation is adequate to supply the current load. Future plans include the addition of a transformer at the STC Apache substation and the noted tie between APS' future Palominas substation and SSVEC's proposed Miller substation, which should improve reliability significantly in the local area. Once completed, all Cochise District load will be able to be carried by the emergency ties at the McNeal and Miller substations without the need for local generation.

3) "A new transformer was constructed at Humbug in 2005 without an oil cache basin. The second unit already has asphalt curbing to assure containment of transformer oil spills. It is assumed that the construction activity may not have been completed or the cache basin may have simply been an oversight given the new focus of fire mitigation."[3]

Status: An oil retention basin will be completed for the second transformer by year end 2006, in compliance with our new standard.

4) "Laguna Feeder #1 was rebuilt in 2005 as an underbuild on a 69 kV line on steel poles. The telephone lines previously in joint use on the old wood pole still remain in service with the poles topped above the telephone line. The wood poles are leaning in such a manner as to likely pose a public safety concern for road

[3] *Id.*

crossings. This is not an APS problem, but is reflective of untimely relocation of joint use facilities on poles that are being removed and replaced."[4]

Status: APS has contacted the local telephone company in Yuma regarding the transfer of communication lines and removal of these poles. We have been informed the work will start in early September, 2006.

5) "One 69 kV steel pole just north of Laguna Substation was observed to have experienced a hit and run vehicular accident. The base of the steel pole was severely crushed. The pole appears to be structurally sound but obviously needs replacement."[5]

Status: APS replaced the subject pole. This incident had occurred just prior to the field visit.

6) "Paulden substation had a larger auger bit stored in an inappropriate location. It was placed in a position that could pose an obstacle for a vehicle's ingress to the site if occurring at night. Simply placing the auger bit adjacent to the substation fence would resolve this safety concern."[6]

Status: The auger bit has been removed from the yard.

7) "The San Luis Substation control house has had a roof leak. A black garbage bag was suspending above electronic equipment on the top of a control rack to protect the equipment until the leak was resolved. The roof leak needs to be repaired and the plastic garbage bag removed to enable proper equipment ventilation void of moisture and to avoid the bag becoming a

---

[4] *Id.*

[5] *Id.*

[6] *Id.*

loose impediment in the control house."[7]

Status: Repairs to the roof of the control house have been completed, and the protective cover removed.

Q. STAFF ALSO RAISED CONCERNS REGARDING THE QUALITY OF SERVICE IN APS' SOUTHEAST DIVISION FOR THOSE PORTIONS OF THE APS SYSTEM THAT PROVIDE SERVICE TO THE COMMUNITIES OF DOUGLAS AND BISBEE. WHAT STEPS HAS APS TAKEN TO IMPROVE SERVICE IN THESE AREAS?

A. APS agrees that reliability in the Southeast Division deserves attention and has made significant efforts to improve reliability. APS continues to patrol underperforming feeders and has performed a substantial amount of maintenance to feeders in the Division.

In 2004, APS began to route and construct a new 69kV transmission line to energize a new substation being located in the Palominas area. At the same time, the main portion of the distribution feeder is being reconstructed on the same poles and will improve reliability of the feeder when completed. This work was scheduled to be performed in four phases, over four years. The new Palominas 69/12kV substation will be placed in service by 6/1/2008. APS recently completed the rebuilding of a portion of the line along Highway 92 that was planned for 2006.

In addition, as part of an agreement between APS, Sulphur Springs Valley Electric Cooperative (SSVEC), and Southwest Transmission Cooperative (STC), APS, SSVEC and STC are performing additions and improvements that will allow for a second emergency tie between APS' Palominas substation and SSVEC's Miller substation. Upon completion in 2009, APS will be able to carry

[7] *Id.*

the entire APS load in the region through use of the two emergency ties without the need for the local generation at our Fairview plant.

Q. STAFF ALSO FINDS THAT THE YEAR 2005 WAS STATISTICALLY NOT A GOOD YEAR FOR APS REGARDING SUSTAINED SERVICE INTERRUPTIONS TO CUSTOMERS. PLEASE EXPLAIN THE CAUSES ASSOCIATED WITH INCREASED OUTAGES IN THE YEAR 2005.

A. As noted in the Staff report, Quality of Service complaints did rise in 2005 compared to 2003 and 2004. However, 2005 was a much more challenging year with respect to weather related outages.

When significant or unusual weather events are removed from the computation, as described below, there is no significant difference in outage rates from 2003 through 2005. Specifically, IEEE 1366-2001, IEEE Guide for Electric Power Distribution Reliability Indices, Section 4.5, Major Event Day Classification, and Annex B, Major Events Definition Development, provide a method to "better reveal trends in daily operation that would be hidden by the large statistical effect of major events." The purpose of determining Major Event Days is to allow major events to be studied separately from daily operation. The following reliability data is the result of removing the Major Event Data.

	SAIFI[8]	SAIDI[9] (minutes)	CAIDI[10] (minutes)
2003	1.23	101	82
2004	1.05	82	78
2005	1.15	105	91

The Major Event Days that were excluded were January 4 and 5 (a significant

[8] SAIFI or System Average Interruption Frequency Index is defined as the total number of customers interrupted divided by the total customer base.

[9] SAIDI or System Average Interruption Duration Index is defined as the total outage duration time seen by customers divided by the total customer base.

[10] CAIDI or Customer Average Interruption Duration Index is defined as the total outage duration time seen by customers divided by the total number of customers experiencing an outage.

winter storm affecting nearly 100,000 customers in northern Arizona), July 17 (a major monsoon in the Metro Phoenix area affecting nearly 130,000 customers), July 23 (a Metro Phoenix monsoon affecting over 20,000 customers), and August 2 (a Metro Phoenix monsoon affecting nearly 30,000 customers). Absent the Major Event days, the statistic difference in performance is not significant.

Further, APS maintains its own quality of service measure called "Clear-Weather SAIFI," which is calculated per IEEE 1366 methods for SAIFI with the exception that weather related causes are excluded. APS uses this indicator to gauge the effectiveness of our maintenance programs through removal of the variability of weather. The "Clear-Weather" reliability data is as follows:

	SAIFI	SAIDI (minutes)	CAIDI (minutes)
2003	0.99	64	64
2004	0.82	57	70
2005	0.84	69	82

APS tracks annual performance for all reliability metrics. The difference in performance is not statistically significant as the annual SAIFI, SAIDI, and CAIDI results are within one standard deviation (as calculated between 1995 and 2005). The general trend has been an improving one, and the results fall within our expected bandwidth of performance.

V. DISTRIBUTED GENERATION WORKSHOP ACTIVITIES

Q. DID YOU PARTICIPATE IN THE COMMISSION GENERIC INVESTIGATION OF DISTRIBUTED GENERATION AND INTERCONNNECTION ("DGI") (DOCKET NO. E-00000A-99-0431)?

A. Yes. I represented APS as a panelist for the DGI Workshop hosted by the Commission on June 28, 1999, and later as a member of both the Access, Metering, and Dispatch Committee and the Commission's DGI Advisory Committee. In addition, I am currently representing APS as a participant in the

ongoing distributive generation workshops ordered by the Commission in ACC Decision No. 67744 (APS Rate Case Settlement) which began in July of 2005.

Q. PLEASE DESCRIBE THE CURRENT ACTIVITIES OF THE COMMISSION ON DISTRIBUTED GENERATION PURSUANT TO ACC DECISION NO. 67744?

A. ACC Decision No. 67744 directed the parties to conduct Workshops on distributed generation which begins by evaluating the following three recommendations made by DEAA:

- utilizing Texas interconnection standards or as an alternative California 21 as a basis for Arizona Standards;
- using Salt River Project's rate E-32 as a basis for a new experimental partial requirements tariff; and
- developing a distributed generation program

The workshops began in July of 2005 and began developing a statewide set of distributed generation interconnection standards. Several workshops were held over the next nine months and the parties a comprehensive set of statewide interconnection standards with agreement on all but 11 issues. Position papers were filed on these 11 issues and the Commission Staff will be coming up with a staff recommended set of statewide standards.

Q. ACCORDING TO THE DIRECT TESTIMONY OF WILLIAM MURPHY ON BEHALF OF DEAA, HE SUGGESTS THAT THE COMMISSION SHOULD HOLD A HEARING TO DECIDE INTERCONNECTION RULES. DO YOU AGREE?

A. I don't believe a hearing is necessary in that we have been working through the collaborative group to develop statewide distributed generation interconnection standards that is under review by Staff. All parties have worked very hard to develop a statewide standard and in the process, have had the opportunity to raise and discuss areas of interest and concerns. Resolution of the remaining 11 issues

should continue to occur through the process Staff is following.

Q. SOLAR ADVOCATES HAS IDENTIFIED ELEMENTS THAT THEY WOULD LIKE TO BE INCLUDED IN A NET METERING POLICY. WHAT IS YOUR OPINION ON THOSE CRITERIA?

A. If any of the criteria include interconnection requirements, resolution of those requirements will occur through the above-mentioned workshop collaborative.

VI. CONCLUSION

Q. AND DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes it does.

ARIZONA PUBLIC SERVICE COMPANY
BARK BEETLE WORKSHEET
WORK ACTIVITY AND EXPENSES
(2003 - 2006)
(Revised Attachment SJB-2)

DISTRIBUTION

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	50,181	90,321	54,749	24,689	
Total Cost	$2,345,584	$6,617,978	$6,282,819	$2,926,307	$5,016,526
Cost / Tree	$46.74	$73.27	$114.76	$118.53	

TRANSMISSION

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	221	35,473	6,701	3,127	
Total Cost	$34,227	$785,606	$1,104,227	$491,986	$843,405
Cost / Tree	$154.87	$22.15	$164.79	$157.33	

TOTAL T&D

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	50,402	125,794	61,450	27,816	
Total Cost	$2,379,811	$7,403,584	$7,387,046	$3,418,293	$5,859,931
Cost / Tree	$47.22	$58.85	$120.21	$122.89	

EXHIBIT
APS-31
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BEFORE THE ARIZONA CORPORATION COMMISSION

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In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744	Docket No. E-01345A-05-0816 **NOTICE OF FILING NOTICE OF ERRATA**
In the Matter of the Inquiry into the Frequency of Unplanned Outages During 2005 at Palo Verde Nuclear Generating Station, the Causes of the Outages, the Procurement of Replacement Power and the Impact of the Outages on Arizona Public Service Company's Customers	Docket No. E-01345A-05-0826 **NOTICE OF FILING NOTICE OF ERRATA**
In the Matter of the Audit of the Fuel and Purchased Power Practices and Costs of the Arizona Public Service Company	Docket No. E-01345A-05-0827 **NOTICE OF FILING NOTICE OF ERRATA**

Arizona Public Service Company hereby files its Notice of Errata to Attachment SJB-1RB to the Rebuttal Testimony of Stephen J. Bischoff. A Revised SJB-1RB attached hereto contains non-material corrections to the 2006 calculations set forth in Mr. Bischoff's Bark Beetle Worksheet 2003-2006 (the revised numbers have been highlighted). Mr. Bischoff will respond to any questions regarding this document when he takes the stand.

Respectfully submitted this 13th day of October, 2006.

SNELL & WILMER L.L.P.

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ARIZONA PUBLIC SERVICE COMPANY
BARK BEETLE WORKSHEET
WORK ACTIVITY AND EXPENSES
(2003 - 2006)

DISTRIBUTION

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	50,181	90,321	54,749	24,692	
Total Cost	$2,345,584	$6,617,978	$6,282,819	$3,119,800	$5,348,229
Cost / Tree	$46.74	$73.27	$114.76	$126.35	

TRANSMISSION

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	221	35,473	6,701	3,127	
Total Cost	$34,227	$785,606	$1,104,227	$420,755	$721,294
Cost / Tree	$154.87	$22.15	$164.79	$134.56	

TOTAL T&D

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	50,402	125,794	61,450	27,819	
Total Cost	$2,379,811	$7,403,584	$7,387,046	$3,540,555	$6,069,523
Cost / Tree	$47.22	$58.85	$120.21	$127.27	

REBUTTAL TESTIMONY OF TERESA A. ORLICK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

EXHIBIT
APS 32
Admitted

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Statement of Qualifications ..... Appendix A

REBUTTAL TESTIMONY OF TERESA A. ORLICK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Teresa A. Orlick, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Manager of Customer Information and Programs for Arizona Public Service Company.

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 REBUTTAL TESTIMONY.

A. My testimony provides an overview of APS' DSM programs for residential and non-residential customers and the progress of those programs to date. Next, I discuss Southwest Energy Efficiency Project's ("SWEEP") proposed Energy Efficiency Standard ("EES") and APS' concerns regarding the effect of SWEEP's proposed changes to the current DSM requirements. In addition, I comment on RUCO's proposed increase in mandatory funding level and testify to APS' support of Staff's recommended DSM Performance Incentive. I also respond to the concerns raised by Western Resource Advocates ("WRA") regarding heat island effect and APS' efforts and recommendations to mitigate this problem.

Finally, I describe APS' Energy Support Programs for Low Income Customers and APS' efforts to implement automatic enrollment in these programs. In

addition, I describe APS' marketing efforts designed to encourage enrollment in these low income programs.

III. OVERVIEW OF DSM PROGRAM PROGRESS TO DATE

Q. WOULD YOU PLEASE PROVIDE AN OVERVIEW OF APS' DSM PROGRAM?

A. Pursuant to Decision Number 67744, APS filed a DSM Portfolio Plan on July 1, 2005, which included 10 proposed DSM programs. The programs were developed with the input and review of the DSM Collaborative working group[1]. These 10 DSM programs for residential, non-residential, and low income customers were approved by the Commission in three separate open meetings, the first of which occurred in August 2005, with the last one taking place in April 2006. The DSM programs are budgeted to spend $48M by year-end 2007.

Q. WHAT DSM SPENDING HAS BEEN ACHIEVED TO DATE?

A. APS has spent $3.2M in 2005 for DSM and $3.5M through August 2006. This spending is across residential, commercial, industrial, schools and low income sectors. Furthermore, the Business Solutions program for non-residential customers has reservations through August 2006 of over $1.5M in incentives for projects that have yet to be completed.

Q. DOES APS EXPECT TO SPEND THE $48M BY THE END OF 2007?

A. Due to the delayed approval of the programs and the steep ramp-up from a level of $1M of DSM spending per year prior to Decision 67744 to the current level of $16M per year, APS does not believe that $48M will be spent by year end 2007. An additional reason for the shortfall in spending by 2007 is the new construction

[1] The DSM Collaborative Working Group is composed of representatives from APS, ACC Staff, RUCO, SWEEP, WRA, Arizona State Energy Office and other Settlement Parties, as noted in Decision 67744.

element of the programs. Although integrating energy efficiency measures in a new building is often the most cost-effective way to achieve energy savings, the completion of many of these projects is likely to extend past 2007.

Q. HOW DOES APS INTEND TO MEET ITS SPENDING OBLIGATION FOR YEARS 2005 – 2007?

A. Any under spending of the $48M will be carried over and spent in subsequent years, in addition to the $16M per year spending requirement for each of those years.

Q. WHAT ARE APS' PLANS REGARDING DSM PROGRAMS BEYOND 2007?

A. It is our expectation that the programs will continue at the same funding level and with the same design until APS submits proposals to modify program design and/or budget requirements and such modifications are approved by the Arizona Corporation Commission ("Commission"). The programs are essentially "evergreen" in the absence of proposed modifications or Commission intervention. The nature of our funding mechanism, comprised of 2 elements – one element is in base rates ($10M) and the other element flows through the DSM Adjustor - allows for DSM programming to continue and grow as cost-effective program opportunities emerge.

IV. ENERGY EFFICIENCY STANDARD PROPOSAL

Q. THE TESTIMONY OF SWEEP PROPOSES THAT APS IMPLEMENT AN EES AS PART OF ITS DSM PROGRAM. DOES APS NEED TO IMPLEMENT AN EES?

A. Not at this time. It is premature to make substantial changes in the DSM Portfolio by imposing a kWh and kW savings target as proposed by SWEEP. The DSM programs now in effect were just recently approved by the Commission and are

still in the early stages of roll-out. The non-residential programs were approved in February 2006 and are only approved on an interim basis, due to the Commission's concerns about obtaining actual program costs and results before granting formal program approval. Furthermore, the residential programs were approved in April and are just getting ramped up.

Very little time has elapsed over which to assess the success of current programs. Time is needed to get DSM programs up to speed, gauge progress, and evaluate what is actually being achieved through the measurement, evaluation and research ("MER") process. Some of the most cost effective program savings (and biggest program spending levels) come from new construction and it may take one to two years before these projects are completed and able to be evaluated.

Q. DOES APS HAVE CONCERNS REGARDING THE PROPOSED GOALS OF THE EES PROPOSAL?

A. Yes. The EES as proposed by SWEEP is a savings goal as opposed to a spending goal. Although both are inextricably linked because spending is needed to achieve savings, a kWh and kW savings target is unnecessary because APS already has a DSM spending requirement that meets energy savings goals and was approved in Decision 67744. APS, Staff and the DSM Collaborative participated in determining what DSM programs should be offered, how funding should be divided, and how much savings could be achieved with the DSM programs at the given spending level. The current spending goal is an effective target because only cost-effective measures are installed. Their cost effectiveness was proven by the Societal Cost Test[2] as performed by APS as well as by Commission Staff

[2] The Commission's 1991 Resource Planning Decision No. 57589 established that the Societal Cost Test should be used for the purpose of establishing whether a DSM program can be considered cost-effective.

("Staff").

Q. WHAT DO OTHERS USE FOR THEIR DSM GOALS?

A. A recent study of 15 jurisdictions with a relatively high level of investment in DSM was conducted by the Regulatory Assistance Project[3], on behalf of CAMPUT[4]. It found that nine of these express their targets in terms of spending, either as a mills/kWh rate or as a percentage of revenues. Assuming the approved programs are cost-effective, savings result as a matter of course.

It is difficult to predict with certainty what savings can be achieved with a given spending goal, particularly with new programs in an untried market. In addition, in order for a savings goal to be achieved, it needs to be adequately funded. A DSM spending goal is more appropriate and ensures that appropriate funding is allocated to DSM rather than guessing what funding might be needed to achieve a set saving goal. This is particularly true when coupled with a framework that provides for stakeholder review of program design and cost effectiveness.

Q. DO YOU HAVE CONCERNS WITH THE LEVEL OF SAVINGS AND THE ASSOCIATED SPENDING IN THE EES PROPOSAL? IF SO, PLEASE ELABORATE.

A. Yes, the proposal is very aggressive. The current DSM spending level of $16 million per year on energy efficiency represents approximately 0.75% of revenue.

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[3] 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.

[4] CAMPUT is the Canadian Association of Members of Public Utility Tribunals, roughly equivalent to the US National Association of Regulatory Utility Commissioners ("NARUC").

According to the 2005 ACEEE Efficiency Program Compendium[5], this exceeds the national average spending of 0.52% of revenue. SWEEP's proposed spending for APS would be equal to nearly 2.5% of revenue. Additionally, only three states nationally (Vermont, Massachusetts, Washington) spend more than 2% of revenue on energy efficiency and these states have gradually increased funding over time. This is likely due to concerns about impact on ratepayers, the impracticality of increasing targets too quickly given the need to build infrastructure and customer awareness over time, and inherent delay in new construction program spending.

Q. SWEEP MAKES COMPARISONS TO OTHER STATES AS PART OF ITS SUPPORT FOR AN EES. ARE THESE COMPARISONS APPROPRIATE?

A. It is arguable whether the seven states used by SWEEP [6] are an appropriate "peer" group. They are Connecticut, California, Maine, Minnesota, Oregon, Rhode Island and Washington. Four of these (Connecticut, California, Maine and Rhode Island) have a significantly higher price per kWh than Arizona, which makes the DSM programs and measures more cost-effective. Major cities in three of these states rank at the top of the country in terms of consumer attitudes about "green" issues (Oregon, California, and Minnesota) which may be used as an indicator of their inclination to adopt energy efficiency measures. All these states have a longer, more consistent history of significant DSM programs to rely on for setting goals. Also, elements of these states' programs are more aggressive. For example, California has more generous incentives that pay up to 100% of a customer's

[5] "American Council for an Energy Efficient Economy ("ACEEE")'s 3rd National Scorecard on Utility and Public Benefits Energy Efficiency Programs: A National Review and Update of State-Level Activity". October 2005, York/Kushler.

[6] (JS, p 5, line 37 to p 6 line 2)

incremental cost. The Commission has determined that end-use measures approved in APS programs should be capped at between 50-75% of a customer's incremental cost. It is unlikely that the current incentive levels for APS would be aggressive enough to meet the EES goal.

Q. HAS SWEEP PROVIDED SUFFICIENT EVIDENCE TO SHOW THAT THEIR PROPOSED FUNDING LEVEL WOULD BE ADEQUATE TO ACHIEVE THE EES GOALS ?

A. APS acknowledges and agrees with SWEEP that it is essential that adequate funding be provided in order to meet DSM goals. SWEEP estimates that 2 mills per kWh of DSM funding would be needed to achieve the EES savings goals. This funding estimate is based on APS achieving DSM savings at an average cost of approximately 1.1 cents per lifetime kWh saved, per Exhibit JS-1, line 13. This is an optimistic assumption given SWEEP's testimony that "The utility program cost to APS ratepayers is...about one to two cents per lifetime kWh saved"[7]. The cost per kWh saved of SWEEP's proposal is on the very low end of this range. At the upper end of the range, two cents per lifetime kWh saved, the requisite funding level would increase from 2 mills to approximately 3.8 mills. Viewed a different way, the proposed funding level would be able to fund approximately half of the EES based on SWEEP's testimony.

Q. WHAT IS THE BILL IMPACT IN TERMS OF COSTS TO CUSTOMERS OF ADOPTING THE EES PROPOSAL BY SWEEP?

A. SWEEP states that their proposed funding in 2007 would grow "from about $25 million to $38 million, an increase of about $13 million."[8] In reality, SWEEP's proposal would be a $28 million increase over base rates and a $22 million

[7] (JS, p. 4, lines 27-29)

[8] (JS, p.7, lines 2-4).

increase over the target level of $16 million.

Q. SWEEP SUGGESTS THAT THE CURRENT PROGRAMS COULD BE EXPANDED TO GET TO A SIGNIFICANTLY HIGHER SPENDING LEVEL. IS THIS FEASIBLE?

A. While it is likely that some expansion is possible, it is questionable as to whether the Commission-approved existing programs could be expanded to the spending and savings levels that SWEEP is proposing. This is particularly true under current Commission criteria where APS incentive levels are set no higher than 75% of incremental cost and the ability to adjust budgets is constrained. APS believes that much more aggressive program design would be required where incentives in some cases were 100% of incremental cost. Also, in many cases to make the energy-efficiency projects economical, the customer may need a shorter payback period than a 75% maximum incentive would afford.

In addition, DSM program implementation requires an infrastructure of contractors, builders, and other trade allies to be developed while programs are ramping up. It also takes time to build customer awareness, interest and adoption. The goal that SWEEP proposes does not appear to reflect program implementation considerations, particularly in the early years.

Q. WHAT ARE YOUR THOUGHTS ON THE RECOMMENDATION BY SWEEP THAT AN EES IMPLEMENTATION PLAN SHOULD BE DEVELOPED?

A. APS believes that SWEEP's proposal that a 12 year Implementation Plan be filed within eight months would have little actionable value in planning and/or implementation of DSM programs because long range results are very difficult to predict. APS believes that periodic planning updates based upon shorter term planning horizons result in a more actionable plan.

Q. WHAT PLANNING REQUIREMENTS DOES APS PROPOSE?

A. APS anticipated the need for periodic planning updates and the 2005-2007 DSM Portfolio Plan filed July 1, 2005 states that APS plans a "biennial submission" of a DSM Portfolio Plan to the Commission. In addition, in spring 2007 APS will be submitting an updated DSM filing ("13-month filing") pursuant to Decisions 68488 and 68648, where the first year's performance and earnings will be incorporated. The schedule for the biennial filing of the DSM Portfolio will be based on the outcome of the 13-month filing. As with the existing Portfolio Plan, APS anticipates working with the DSM Collaborative and Staff to jointly develop the plan.

Q. IS AN ALTERNATE DSM FUNDING MECHANISM NEEDED IN THIS RATE CASE?

A. No, the DSM adjustor mechanism was created to provide the ability to alter DSM funding with Commission approval outside of a rate case to match spending. Decision 67744 authorizes an annual "minimum spending" requirement of $10 million per year in base rates with an additional $6 million authorized through an adjustor. In fact, SWEEP and RUCO both acknowledge that due to delays in approval process, APS will need to "catch up" with the current level of funding authorized in base rates. In the future when the Portfolio is spending at the $16M level, the adjustor will allow for additional program funding. APS supports the current approach, with a combination of base rates and the DSM adjustor mechanism. This mechanism provides a flexible means of cost recovery, which can be adjusted between rate cases as needed. In fact, RUCO's proposal, as outlined in Ms. Diaz Cortez' testimony, to increase the annual mandatory spending in the surcharge from $6M to $10M post-expiration of the Settlement Agreement is not needed at this time due to the flexibility of both the programs

and the funding mechanism. As existing programs mature and new programs evolve, spending levels may increase further. The DSM adjustor mechanism is in place to recover any additional spending for approved programs.

V. DSM PERFORMANCE INCENTIVE

Q. DOES APS AGREE WITH STAFF'S ANALYSIS OF THE DSM PERFORMANCE INCENTIVE?

A. Yes. APS agrees with Staff that the performance incentive is appealing as a tool to reward a utility's performance in conducting successful DSM programs.[9] APS also agrees with Staff's recommendation to set the performance incentive share at 10% of the net benefits from the energy efficiency achieved through approved DSM programs and that the incentive should be capped at 10 percent of spending inclusive of the performance incentive.[10] APS also agrees with Staff's recommendation that APS should share in the benefits of the DSM measures as they are placed into service and expenditures are incurred, and that APS should include a request for the performance incentive payment in each semi-annual report filing. [11]

Q. WHAT SPECIFIC CALCULATIONS OR METHODOLOGY SHOULD BE USED TO DETERMINE THE NET BENEFITS OF DSM MEASURES UNDERTAKEN?

A. In Arizona, the Societal Cost Test is used as the measure of program benefit/cost ratio. This test considers the net present value of the benefits of a program that derive from the utility avoided cost savings (capacity, energy/fuel/O&M, T&D savings) as a result of kWh and peak kW savings from DSM measures

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[9] (Direct Testimony of Jerry D. Anderson (JDA), p. 9, lines 14-19)

[10] (JDA, p.10, lines 5-8).

[11] (JDA, p.12, lines 8-14).

undertaken. Program costs include the net present value of all the utility non-incentive program costs and the customer's incremental cost for upgrading to a more energy efficient end use. The formula is:

Net Benefits = Total Societal Benefits – Total Societal Cost

Where:

Total Societal Benefits is the utility avoided cost savings,

and

Total Societal Cost is the sum of utility non-incentive program costs and customer incremental cost

This is the same basic cost/benefit equation that Staff used in their calculation of program net benefits, as demonstrated by Decisions 68488 and 68648.

In addition, APS agrees to provide Staff with backup workpapers and input data to substantiate numbers for net benefits and performance incentives included in each semi-annual DSM report.

Q. FOR THE PURPOSES OF THE PERFORMANCE INCENTIVE COMPUTATION, HOW WILL KW AND KWH SAVINGS BE DERIVED?

A. These savings are the product of the number of measures installed and their associated savings per unit. The measures installed are actual figures, and for prescriptive measures APS recommends that program savings should be based on the program filed savings numbers until such time that MER results are available. It is important to clarify that the program filed savings numbers are NOT engineering calculations. Rather they reflect actual savings from field measurements collected over many years of energy efficiency program implementation, in environments representative of our service territory. Additionally, these savings figures are well vetted by many experts and it is common industry practice to use these in DSM program design and evaluation

and for purposes of performance incentive calculations. For custom projects, an energy savings analysis will be performed for each specific project, they must follow strict program criteria, and realistic savings figures are expected to result. All custom energy savings analysis will be verified by an energy engineer. As MER results become available, these results will be used to refine savings estimates going forward.

VI. RESPONSE TO TESTIMONY OF WESTERN RESOURCE ADVOCATES.

Q. DOES APS SUPPORT THE CONCEPT OF MITIGATING THE HEAT ISLAND EFFECT IN METROPOLITAN AREAS WITHIN ITS SERVICE TERRITORY?

A. Yes, APS does support efforts to mitigate the heat island effect, especially when tied to energy conservation. In fact, APS is a sponsor of the ASU Global Institute for Sustainability ("GIOS"), through its Sustainable Materials and Renewables Technologies Alliance ("SMART"), and as a Sustainer/Lifetime contributor to this effort. The GIOS was established to advance interdisciplinary research on environmental, economic and social sustainability, especially as it relates to urban areas. The SMART Alliance provides information on research, education and resources to enable metropolitan areas to be more sustainable and less vulnerable to the heat island effect.

Q. WOULD APS BE WILLING TO BRING OUTSIDE EXPERTS TOGETHER TO INFORM AND EDUCATE THE DSM COLLABORATIVE GROUP ON HEAT ISLAND EFFECTS?

A. Yes, APS will schedule a DSM Collaborative Meeting that will include a presentation from a representative of ASU's GIOS to provide an update on actions and research currently underway to mitigate the heat island effect throughout Arizona.

Q. DO YOU AGREE WITH WRA'S PROPOSAL TO CREATE A NEW DSM PROGRAM THAT IS DESIGNED SPECIFICALLY TO REDUCE URBAN HEAT ISLAND EFFECTS?

A. Because we feel APS' current DSM Programs sufficiently covers these types of measures, a separate and distinct program is not needed at this time. APS' non-residential DSM Programs already include a custom efficiency component in which any measure that falls outside the prescriptive list of measures might qualify. When a customer files an application for a custom project, the entire project and all energy efficiency measures proposed is reviewed to determine the associated energy savings and benefit to society using the "Societal Cost Test". All measures that demonstrate kWh savings and pass the test would qualify for the custom incentive. This seems a very logical place to review and provide incentives for projects like those suggested by Dr. Berry.

Q. WHY IS THE CUSTOM APPLICATION A LOGICAL PLACE TO CONSIDER PROJECTS OF THIS NATURE FOR DSM PURPOSES?

A. Because of the many different ways to address urban heat islands, these projects are often unique in nature. The type of project and energy efficiency measures being installed will likely vary. The type of business and size of the facility in square footage is also likely to vary from project to project. Therefore, developing "prescriptive" measures (defined as a pre-approved "menu" list) for these kinds of unique measures may not be practical, and the custom application where a comprehensive review of each project is completed is warranted.

Q. WHAT OTHER REASONS MIGHT WARRANT THE REVIEW OF HEAT ISLAND MITIGATION MEASURES AS CUSTOM VERSUS PRESCRIPTIVE?

A. Some of the cool roof measures included in WRA's urban heat island program proposal have already been disallowed as end-use measures in our DSM

Programs, as they did not receive Commission approval in Decision No. 68488. In fact, Staff's recommendation in that Decision states "that no incentives be paid for the cool roofs measure at this time". This would include cool-roof membranes and cool-roof reflective coatings.

Furthermore, any additional measures or new program designed to reduce the urban heat island effect should need to demonstrate energy savings and pass the Societal Cost Test to qualify, just as any other measure in our approved programs are required to do.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION REGARDING THIS ISSUE.

A. My recommendation is that projects such as those proposed by WRA that incorporate measures to reduce the urban heat island effect, can be reviewed and approved, on a custom basis, under currently approved programs. Applications including heat island mitigation measures (e.g., landscape vegetation, certain cool materials, etc.) are eligible for consideration of incentives when applied for as part of a custom application. However, some cool roof measures would be excluded as Staff and the Commission did not approve cool roofs (reflective coatings and membranes) incentives because they did not pass Staff's analysis and calculation of the Societal Cost Test.

Furthermore, much research and development is still being conducted related to the heat island effect and APS continues to support these efforts as part of ASU's GIOS program. We believe that the research underway should yield substantial results before proceeding down the path of developing an entire heat island effect DSM program.

VII. <u>APS ENERGY SUPPORT PROGRAMS FOR LOW INCOME CUSTOMERS</u>

Q. PLEASE PROVIDE AN OVERVIEW OF APS' E-3 AND E-4 PROGRAMS.

A. APS' Energy Support Program ("E-3") offers discounts up to 40% off the cost of electricity for customers who meet certain income guidelines. Specifically, the income guidelines are based on 150% of the federal poverty guidelines as determined by the Arizona Department of Economic Security ("DES") and changed every July 1. Additionally, customers on E-3 are exempt from the Power Supply Adjuster ("PSA") charges.

The E-4 program incorporates a medical care equipment program which provides additional discounts to eligible customers who qualify for the E-3 discount. The customer needs to provide a letter from their medical provider showing that they require some type of durable medical equipment, for example, an oxygen concentrator.

Q. HOW DO CUSTOMERS ENROLL IN ENERGY SUPPORT PROGRAMS?

A. Once a year, APS sends program information and applications to all residential customers not already enrolled in E-3 and E-4. This solicitation includes a postage prepaid return. Applications are also distributed at APS offices, social service agencies and are downloadable on aps.com. The customer whose name is on the APS account is required to fill out, sign, and send the completed application to DES. DES is responsible for processing the application and determining the eligibility of the applicant, and notifying APS to enroll the applicant.

Q. FOR HOW LONG DOES AN ELIGIBLE CUSTOMER REMAIN ON THE E-3 PROGRAM?

A. The customer can remain on E-3 indefinitely as long as they continue to meet the income guidelines. The customer must recertify for the program each year. DES

automatically sends the necessary paperwork for recertification. The customer must return the paperwork to maintain the discount.

VIII. AUTOMATIC ENROLLMENT FOR E-3

Q. WHY IS APS INCLUDING A DISCUSSION OF AUTOMATIC ENROLLMENT IN THE LOW-INCOME PROGRAMS?

A. In April 2006, Decision 68685 (APS Emergency Rate Case) requested APS to propose ways to implement automatic enrollment into our low-income programs for customers who participate in applicable means-tested assistance programs.

Q. WHAT STEPS HAS APS TAKEN TO INVESTIGATE AUTOMATIC ENROLLMENT IN ITS LOW INCOME PROGRAMS?

A. In 2005, APS met with the Arizona Community Action Association ("ACAA") and DES to determine the feasibility of automatically enrolling food stamp recipients. After several meetings, there was a suggestion to have DES provide an electronic file with all of their food stamp recipients to APS. The parties were then tasked with investigating the issues involved with this approach.

Q. AFTER INVESTIGATION, WHAT CONCLUSIONS WERE REACHED BY THE PARTIES ON THE FEASIBILITY OF AUTOMATICALLY ENROLLING FOOD STAMP RECIPIENTS?

A. The parties came to the conclusion that taking this approach could potentially involve legal liability involving the transmittal of confidential client information, especially as it relates to income. According to the "Authorization for Release of Information" form that is part of the DES application for state assistance, "DES will not release this information to any other person or agency outside of the DES or its agents."

Q. WHAT OTHER STEPS HAS APS TAKEN TO IMPLEMENT AUTOMATIC ENROLLMENT?

A. APS has an Electronic Agency Guarantee ("EAG") website that allows authorized community agencies to verify a client's account data, and post a payment guarantee. It is used to facilitate payments from various assistance programs, including the federal Low Income Home Energy Assistance Program ("LIHEAP"). Since LIHEAP uses the same income guidelines as APS' E-3 program, which is 150% of the federal low income guideline, this provides an excellent proxy to qualify a customer for E-3. Therefore we have integrated E-3 enrollment into this process and can enroll LIHEAP clients to our program.

Q. WHAT STEPS HAS APS TAKEN TO IMPLEMENT E-3 ELECTRONIC SIGN-UP USING THE EAG?

A. On June 1, 2006, APS initiated a pilot program to test this concept. Now, when a customer goes to a community action agency and is eligible for LIHEAP assistance, the caseworker informs the client that they can also enroll in APS' E-3 Low Income program and receive a discount on the cost of their electricity. If the customer agrees, the caseworker can enroll the client into E-3 at the same time that they provide the payment guarantee.

Q. PLEASE DESCRIBE THE PROCESS FOR ENROLLMENT IN THE E-3 PROGRAM VIA EAG?

A. When an APS customer goes into a community action agency for assistance with their utility bill, the agency determines the customer's eligibility for LIHEAP. If they are eligible, the case worker signs onto the EAG website and is able to look up the customer's information. On that page, there is a check box for E-3. Once clicked, the system asks if the customer is eligible for E-3. If yes, then the system asks if the customer has agreed to sign up for E-3. If the answer is yes, the checked box is selected. At this point, the case worker clicks "submit" and the E-3 application information is sent via an encrypted e-mail to a secure DES

mailbox. DES gets the e-mail and processes the E-3 application.

Q. WHAT AGENCIES PARTICIPATED IN THIS PILOT PROGRAM?

A. Participating agencies for the pilot program included Community Action Human Resource Agency ("CAHRA") and the Coconino County Community Services.

Q. WHAT IS THE STATUS OF APS' PILOT PROGRAM?

A. The pilot program commenced in July 2006 and as of September 1, 2006, there have been 70 enrollments. APS analyzed the pilot results and obtained feedback from DES. Initial results indicate the system is working effectively, and APS has recently opened the EAG/E-3 process to all agencies utilizing the EAG to make LIHEAP assessments and City of Phoenix, five Maricopa County Community Services offices, Western Arizona Council of Governments ("WACOG") and Gila County Community Action Program have started.

Q. ON A GOING-FORWARD BASIS, WHAT ARE APS' FUTURE PLANS RELATED TO THE EAG / E-3 PROGRAM?

A. During the pilot phase, APS tied income verification to eligibility for LIHEAP, since the guidelines were identical. In the future, APS may want to add other programs which use the same income guidelines, for example, the Temporary Assistance to Needy Families ("TANF") and food stamps. APS is exploring these programs along with the agencies that administer them.

APS is interested in expanding the number of agencies utilizing EAG. Currently, there are 28 agencies using EAG. APS continues to approach other agencies about using EAG. For instance, on May 15, 2006 APS held a forum at which details of the EAG / E-3 program were shared with 20 community action agencies. APS has been contacting agencies that perform means-testing for other

programs (e.g. TANF and food stamps) to assess their willingness and interest in partnering with APS to electronically sign-up customers.

Q. PLEASE EXPLAIN WHY APS IS PROPOSING TO MODIFY THE ADMINISTRATION OF THE E-3 AND E-4 DISCOUNT PROGRAMS.

A. The Company is proposing to modify the Plans of Administration for Schedules E-3 and E-4 in order to facilitate the automatic enrollment process, as discussed in the rebuttal testimony of Mr. DeLizio. The reason we would like to broaden this language is to provide us with the flexibility to pursue other enrollment options, such as allowing community agencies that have access to APS' EAG website the ability to also enroll their clients into E-3. Since these agencies have programs that follow the same income guidelines, it makes sense to provide them with the ability to also enroll their clients directly into our E-3 program. Considering the emphasis that the Commission is placing on our Low Income outreach efforts, this change would allow us to broaden our reach to enroll likely candidates in the program. Additionally, we have spoken with DES and they are amenable to this change.

IX. E-3 AND E-4 MARKETING EFFORTS

Q. PLEASE DESCRIBE STEPS APS HAS TAKEN TO PROMOTE ITS E-3 AND E-4 LOW INCOME DISCOUNT PROGRAM.

A. APS sends program promotions via customer bills to all residential customers every year and applications are always available at Community Action Agencies and government economic assistance offices. APS promoted the programs via articles in the April/May 2005, October/November 2005 and June/July 2006 APS "Arizona Lifestyle" newsletters, and expanded information on aps.com, including an on-line application for customers. APS held a forum with numerous social services agencies in an effort to create a joint partnership with these agencies to

promote the low income assistance programs. In addition, APS has engaged in a relationship with HUD in an effort to coordinate marketing and promotion of E-3 and E-4 to their low-income housing clients.

Q. PLEASE DESCRIBE APS' ENERGY SUPPORT PROGRAM MARKETING AND PROMOTIONAL EFFORTS TO TRIBAL CUSTOMERS.

A. As a result of Decision 67744, APS developed marketing efforts to attract a greater number of Tribal customers to E-3 and E-4. In the spring of 2006, APS sent letters to all of our Tribal customers explaining the benefits and eligibility criteria of the E-3 and E-4 program and included the application. This mailing included an endorsement by Tribal leadership. In the letter, leaders of the Navajo and Hopi Nations encouraged their members to participate in the programs. This was followed in the summer of 2006 with media promotion of E-3 to its tribal customers through print and radio ads. While the response to these marketing efforts has increased Tribal customer enrollment by over 150% in 2006, APS is in the midst of an additional direct-mail campaign to yet further increase Tribal customer participation.

Q. PLEASE DESCRIBE THE CURRENT ENROLLMENT FOR E-3 AND E-4 LOW INCOME PROGRAMS.

A. During the Test Year, APS had an enrollment of approximately 28,000 on the E-3 and E-4 low income program, which included 206 customers on Tribal lands. By August 2006, enrollment increased to over 36,000 with 566 Tribal customers.

X. CONCLUSION

Q. AND DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

APPENDIX A

Statement of Qualifications

Teresa A. Orlick

Teresa A. Orlick is Arizona Public Service Company's Manager of Customer Information and Programs. In that capacity she oversees the planning, marketing and implementation of customer programs for APS. These programs include the portfolio of demand side management programs, SurePay (the APS direct debit payment plan), Equalizer (the APS levelized payment plan) and E-3/E-4 (the APS low income discount plan). She also oversees the market research function for APS.

Before joining APS, she was the Marketing Manager at Wisconsin Electric and prior to that, at Wisconsin Natural Gas, where she oversaw the marketing of energy efficiency and energy-related products for the residential and multifamily market segments. She also managed the Residential Conservation Service home energy audit program.

She has served on various professional committees including EPRI's Residential Task Force, and EEI's Residential Marketing Communications Task Force and Residential Strategic Action Committee.

She received a Bachelors of Science degree in Business Administration from Marquette University in Wisconsin.

REJOINDER TESTIMONY OF TERESA A. ORLICK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

October 4, 2006

EXHIBIT
APS 33
Admitted

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III. DSM Program Update 2

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REJOINDER TESTIMONY OF TERESA A. ORLICK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E-01345A-05-0827)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Teresa A. Orlick, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. To reconfirm the positions in my rebuttal testimony, respond affirmatively to the Staff's proposal on the Demand Side Management ("DSM") Performance Incentive, and provide a DSM program update.

Q. DOES YOUR SILENCE REGARDING ANY OF THE ISSUES DISCUSSED BY OTHER PARTIES INDICATE AN ACCEPTANCE OF THOSE POSITIONS BY THE COMPANY?

A. No, it does not. For those issues, the Company maintains its positions discussed in previous testimony.

II. DSM PERFORMANCE INCENTIVE

Q. HAVE YOU READ THE SURREBUTTAL TESTIMONY ON THE TOPIC OF DSM PROVIDED BY WITNESSES J. ANDERSON (STAFF), J. SCHLEGEL (SWEEP), D. BERRY (WRA) AND M. DIAZ-CORTEZ (RUCO)?

A. Yes, I have.

Q. PLEASE PROVIDE YOUR RESPONSE TO STAFF'S PROPOSAL FOR THE DSM PERFORMANCE INCENTIVE.

A. I agree with the proposal provided in Staff's testimony (JD Anderson, page 3 line 23 through page 4 line 13) regarding the DSM Performance Incentive. In particular, I agree with using the measured savings developed by the Measurement, Evaluation and Research (MER) contractor to determine the net benefits of the DSM Portfolio starting with the second semi-annual DSM report for 2007. Prior to that period, APS agrees to use current and regionally similar figures for the energy savings to determine the DSM Portfolio net benefits, which will include input and review from the MER contractor. There may be instances where the program-filed savings numbers are the most current and regionally similar.

III. DSM PROGRAM UPDATE

Q. PLEASE UPDATE US ON THE PROGRESS OF THE DSM PROGRAMS.

A. Actual spending January 2005 through August 2006 totaled $6.7M. At this time, we estimate that spending for the remainder of 2006 will reach $5.9M, for a total program spending through year-end 2006 of $12.6M.

Q. HOW MANY MWH SAVINGS RESULT FROM THE TOTAL DSM SPENDING THROUGH END OF 2006?

A. We will have saved, in annual terms, over 127,000 MWh resulting from this DSM spending and the corresponding DSM measures installed in 2005 and 2006. Mr. Ewen provides an updated estimate of the financial impact of these reduced sales in his Rejoinder Testimony.

Q. DO YOU STAND BY YOUR REBUTTAL TESTIMONY IN ALL OTHER REGARDS?

A. Yes, I do.

Q. HAS WITNESS ANDERSON, SCHLEGEL, BERRY OR DIAZ-CORTEZ

ADDED ANY NEW OR ADDITIONAL INFORMATION OR EVIDENCE THAT WOULD CAUSE YOU TO CHANGE ANY OTHER ASPECT OF YOUR REBUTTAL TESTIMONY?

A. No.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DIRECT TESTIMONY OF EDWARD Z. FOX

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

EXHIBIT
APS 34
Admitted

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DIRECT TESTIMONY OF EDWARD Z. FOX
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Edward Z. Fox. My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR POSITION AND WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am Vice President of Communications, Environment and Safety for Arizona Public Service Company ("APS" or "Company"). In that capacity, I am responsible for environmental, health and safety compliance and policy, as well as corporate communications and communications-related policies. I oversee APS programs that identify and help find system applications for new technologies, such as fuel cells, and I oversee the implementation of the Environmental Portfolio Standard ("EPS"), a mechanism instituted by the Arizona Corporation Commission ("Commission") to promote the development and use of renewable resources. I am also responsible for corporate security and facility maintenance and management. A statement of my qualifications is attached as Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will discuss the changes that APS will make at its coal-fired generation facilities through 2009 to minimize the operational, environmental and financial impacts associated with existing and future federal and state laws, regulations and policies. I will present the APS proposal for an Environmental

Improvement Charge ("EIC"), an adjustment mechanism that would provide for a timely recovery of the cost for the substantial capital investment necessary for adding or improving environmental controls in the Company's coal generation facilities. I am also providing testimony about the Green Power offerings, which make a variety of renewable resources available to customers. In addition, I explain the Company's net metering proposal to compensate customers that have renewable resources facilities of 10 kW or less who provide their excess energy to the APS grid. Finally, I comment on the Commission's EPS rules.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. APS' coal plants are a vital part of the Company's diverse fuel mix that provides its customers with greater price stability and reliability than would otherwise exist without these plants. While these plants meet all current environmental regulations, they do present some unique challenges. APS is knowledgeable about the potential environmental impacts of its coal-burning operations and the need to significantly reduce emissions over the next several years to comply with existing, proposed and expected laws and regulations. APS estimates that the necessary environmental changes to the Cholla Power Plant will cost approximately $135 million over the next several years. Additional improvements beyond five years have not yet been determined, although it is expected that the Four Corners and Navajo Power Plants will also need improvements in the future. The acceleration and scale of environmental compliance costs have reached a point where an adjustment mechanism is necessary to timely recover the cost of investing in and maintaining these environmental improvements. For these reasons, APS is requesting an EIC,

which would allow the Company to recover the Commission-approved cost associated with the investment and expenses for needed environmental improvements at APS' generation facilities.

I am also presenting testimony regarding the Company's proposals for Green Power offerings and net metering offering. In relation to another environmental issue, I am also commenting on the EPS rules. Due to the adjustment mechanism established in the last rate case, APS is not asking for any adjustment in this case.

III. ENVIRONMENTAL IMPROVEMENT CHARGE

Q. PLEASE EXPLAIN THE ENVIRONMENTAL CHALLENGES THAT APS FACES.

A. Reliable and affordable energy drives economic development. The fuel sources for this energy and how it is delivered to the customers have varying costs, and effects on the environment. The ongoing challenge for the Company is meeting Arizona's growing energy demands efficiently, with limited rate impacts, while minimizing the environmental impact.

To provide reliable electric service to its customers, APS has invested in several generating plants. A significant part of APS generation capacity is from coal-burning plants, including the Cholla Power Plant located near Joseph City, Arizona; the Four Corners Power Plant, which is located in the Navajo Nation in northwestern New Mexico; and the Navajo Power Plant,[1] located in northern Arizona. These plants are located near one or more large national parks and

[1] APS has a 14% ownership interest in the Navajo Plant.

wilderness areas, which are designated as mandatory "Class I Areas"[2] under the Clean Air Act.

The Company supports the EPS and the increasing role of clean renewable energy, but for the foreseeable future, there is a continued need to use fossil fuels. In this context, APS believes that its existing fossil fuel operation must be managed to reduce its environmental footprint, to the extent practical, and in a manner that ensures compliance with existing and anticipated environmental laws.

Coal-fired generation represents a significant percentage of the APS generation portfolio. While the environmental impacts of coal differ from other fuel sources, coal is a relatively low-cost fuel, and it is not realistic to expect this energy source to be replaced by other cleaner, cost-effective technology in the near future. We must therefore assure that existing units meet the emissions standards required under the current regulatory scheme and take the actions necessary to protect Arizona's environment.

Q. WOULD YOU EXPLAIN HOW THE COMPANY VIEWS ITS OBLIGATIONS RELATED TO ENVIRONMENTAL ISSUES?

A. APS understands that in order to be successful in the future, we must continue on a path of continuous improvement and maintain a rigorous focus on doing the right thing, which includes taking care of the environment. APS is committed to responsible environmental practices. We endeavor to go beyond basic

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[2] The Environmental Protection Agency ("EPA") defines a "Class I Area" as all international parks and national wilderness areas which exceed 5,000 acres in size, national memorial parks which exceed 5,000 acres in size, and national parks which exceed 6,000 acres in size that were in existence on August 7, 1977. *See* 42 U.S.C. § 7472.

compliance, where those activities protect public health and the environment and are consistent with sound business practices and goals.

Our commitment to continuous improvement includes a regular review of environmental stewardship, in light of advances in technology and new understandings in environmental science. In this regard, the Company is pursuing an energy resource plan that looks to the future and recognizes the importance of environmental protection, energy conservation and efficiency. We have been active in research and development of solar energy for several decades and are recognized as a leader in advancing solar technology.[3] APS has constructed solar power plants around Arizona, including one in Prescott that upon completion is expected to be one of the largest photovoltaic plants in the world. In addition, the Company is involved in a variety of environmental projects, including biomass, biogas, geothermal technologies, wind energy, and the development of renewable fuels.

We have also developed programs that allow our customers to participate in the use of renewable energy. APS has offered the Solar Partners Program since 1997, under which APS customers were invited to purchase energy generated by solar power plants. This was the first "green energy" offer in the state of Arizona. With this filing, APS is seeking Commission authorization to offer a more robust opportunity for its customers to purchase energy generated from a

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[3] As far back as 1954, APS was the principal organizer of the first International Solar Energy Exposition. In response to the 1973 embargo, APS helped organize the Arizona Solar Energy Research Committee (now the Solar Energy Advisory Council), and developed internal research programs. In 1988, APS built its Solar Test and Research Center, which is utilized by scientists, engineers and students from around the world to test the latest developments in solar technology.

variety of renewable resources. The new Green Power offerings are discussed later in my testimony and in Mr. Gregory DeLizio's testimony.

Our approach to protecting the environment is proactive as we strive to continuously reduce the release of substances that may impact the environment. We work to stay ahead of the regulatory curve through a dialogue with the regulators and the environmental community. By taking a collaborative approach, we can realistically anticipate new requirements, allowing us to make emission reductions or operational changes quickly and cost-effectively. It also allows us to avoid the costs of enforcement or citizen suit litigation, which is a win-win situation for APS, the Arizona environment and the regulators.

Q. HOW DOES THE STATE BENEFIT WHEN AN ELECTRIC COMPANY INVESTS IN ADDITIONAL MEASURES TO PROTECT THE ENVIRONMENT?

A. In addition to the health benefits for Arizona citizens that result from less pollution and waste, it is important to note that Arizona is home to many significant natural wonders, including the Grand Canyon National Park and the Petrified Forest National Park. The EPA has designated these areas as Class I Areas and there are special visibility requirements that apply, pursuant to the Clean Air Act. APS understands the need to reduce emissions from its generating plants to protect the national parks.

Q. DOES THE COMMISSION HAVE A ROLE IN ADDRESSING ENVIRONMENTAL CONCERNS IN ARIZONA?

A. It is evident that this Commission has a real commitment to protecting Arizona's environment. For example, this Commission has expedited the development of

renewable energy resources through its EPS rules.[4] In addition, as part of the Company's last rate case, the Commission supported renewable energy by requiring a special renewable energy solicitation and ordering APS to seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources.

While not imbued with the environmental regulatory authority of the EPA or the Arizona Department of Environmental Quality ("ADEQ"), the Commission does oversee the public utility industry and has the authority to set rates that can foster environmental improvement by the public service corporations that it regulates. This can be accomplished by approving mechanisms that permit utility companies to make and recover capital expenditures to upgrade facilities for environmental purposes. The Company's proposed EIC is such a mechanism.

Q. WHY IS APS PROPOSING AN EIC?

A. As the Vice President responsible for APS' environmental performance, I am continually focused on the actions APS should take to protect human health and the environment, while providing reliable energy to our customers. This means complying with existing laws and anticipating future requirements and, where appropriate, exceeding requirements. APS works proactively with the environmental community, environmental agencies, and vendors to continually analyze the environmental impact of our operations and to plan improvements to improve the Company's environmental profile, including reducing emissions

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[4] A.A.C. R14-2-1618

from the Company's coal plants. Due to the extensive capital required for many of these improvements, it was clear that funding them would be a challenge. The proposed EIC would allow the Company to implement the planned improvements and recover the costs of these capital projects on an annual basis, as the costs are incurred. This approach provides a mechanism to do the right thing. I believe improved environmental performance from the reliable, low cost generation sources are a natural compliment to the renewable energy sources required by the Commission's EPS. The common goal is environmental quality combined with a reliable, affordable source of electricity for customers.

As set forth in the APS EIC Plan (Attachment EZF-1), numerous changes are planned for the Cholla Power Plant in the foreseeable future to meet environmental requirements. Additional improvements at Four Corners and Navajo Power Plants may also be necessary and/or desirable in the coming years. As expenditures are made, an EIC would provide timely recovery of the prudent and reasonable costs required for these environmental projects.

Q. PLEASE DESCRIBE THE EIC THAT THE COMPANY IS PROPOSING.

A. In general terms, the EIC mechanism would recover the on-going cost for environmental projects where the Commission had pre-approved the investments and associated expenses for environmental improvements at APS' generation facilities. The Company's current request under the proposed EIC is for coal-fired generation improvement costs; however, other kinds of environmental improvement costs, such as for water and waste, are anticipated and under APS' proposal, could be included in the EIC. Mr. DeLizio addresses the EIC in detail in his testimony.

Q. WHY SHOULD CAPITAL INVESTMENTS FOR ENVIRONMENTAL IMPROVEMENTS BE TREATED DIFFERENTLY FROM ANY OTHER CAPITAL INVESTMENT?

A. Unlike other capital expenditures, environmental expenditures do not produce revenue that can be used to offset the cost of the improved facilities. For example, the cost of a new substation is recovered, at least in part, by the additional revenues from the new customers that the substation will serve. In contrast, environmental expenditures at the Cholla, Navajo and Four Corners Power Plants have no revenue benefit associated with them. While the Company recognizes the importance of compliance and the societal benefits of cleaner air and environmental enhancement, delayed recovery of these substantial costs could adversely affect APS' earnings and adversely impact the Company's financial ability to fund environmental projects.

Q. ENVIRONMENTAL CONCERNS HAVE BEEN AN ISSUE FOR MANY YEARS, SO WHY IS THE COMPANY REQUESTING AN ENVIRONMENTAL ADJUSTMENT FACTOR AT THIS TIME?

A. APS is proposing this specific mechanism to recover environmental compliance costs because additional mandates are accelerating the timing and level of cost associated with environmental compliance activities. Upgrading existing facilities and reducing emissions from coal generation takes on additional urgency in light of increased volatility of natural gas prices; more stringent requirements to reduce sulfur dioxide ("SO_2") and nitrogen oxides ("NOx"); new requirements on mercury emissions; and the increased probability that carbon dioxide ("CO_2") will be regulated in the foreseeable future.[5]

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[5] CO_2 is an emission related to global warming and climate change, but it is not a regulated pollutant under the Clean Air Act and is addressed in this testimony only to the extent that it is an environmental issue that the Company will confront over the next several years.

Environmental compliance activities are a legitimate and unavoidable cost associated with the provision of electric service. Implementing an EIC would benefit APS customers by keeping the low-cost coal-burning units viable, would benefit Arizona's economy through the employment of a local labor force and local tax base of these plants, and would benefit Arizona as a whole by protecting the State's environment. Importantly, it will also minimize the impact on earnings as well as cash flow for these significant projects. For these reasons, APS is urging the Commission to adopt the EIC to address these concerns.

Q. HOW DOES THE GENERATION OF ELECTRICITY IMPACT THE ENVIRONMENT?

A. SO_2, NOx, particulate matter and mercury emissions are by-products of coal-burning generation plants. The EPA and ADEQ are required to set limits for these pollutants to protect public health and the environment. These limits are adopted into the coal plants' operating permits. The expectation is that by meeting these permit limits, the emissions will not negatively impact the environment or public health. However, these limits are based upon what we currently know, and as the science regarding these pollutants improves, the regulatory agencies' ability to set appropriate emission limits increases. Thus, since the inception of the Clean Air Act in 1970, EPA and/or ADEQ have periodically set new, more stringent limits for operating sources of air emissions. The agencies setting these limits anticipate that industry will respond by installing state-of-the-art pollution control technology as the standard method to minimize the emission of pollutants into the environment. Specific concerns regarding emissions from coal plants and emission control technologies are discussed below.

Sulfur Dioxide: SO_2 is the major pollutant associated with acid rain and has a negative impact on visibility. SO_2 emissions also contribute to increased fine-particulate matter concentrations downwind from emission locations. The western United States does not have an acid rain problem at this time; the primary purpose for SO_2 emission reductions in the West is to improve visibility in Class I Areas, such as national parks and designated federal wilderness areas. Current regulations[6] require certain facilities, including Cholla 2 and 3, Four Corners and Navajo, to install the "Best Available Retrofit Technology" ("BART") no later than 2013. The common emission control technology for SO_2 emissions is scrubbers that remove the SO_2 from the flue gas after the coal is combusted.

Nitrogen Oxides: NOx emissions contribute to visibility degradation, as well as, elevated ozone levels, acid deposition and nitrogen deposition. NOx emissions also contribute to an increase in fine-particle concentrations. Recognized NOx control technologies include low NOx burners, overfired air and, in some situations, the more expensive Selective Catalytic Reduction ("SCR") technology. New NOx limits have been included in recently proposed legislation and in EPA rules to protect visibility.

Particulate Matter: Particulate matter contributes to reduced visibility. In addition, particulate matter has the potential to cause exceedances of both "opacity" limitations and the EPA health-based standard for particulate matter

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[6] 40 C.F.R. § 51.300 *et seq.*

under the National Ambient Air Quality Standards.[7] The common environmental control technology is bag-houses.

Mercury: Mercury is a naturally occurring element that is released into the atmosphere when coal is burned. Some of the mercury may be deposited in lakes and streams, where it can be ingested by fish that cannot metabolize or excrete the mercury causing bioaccumulation in their tissues. The common mercury emission control technology is bag-houses, as well as activated carbon injection.

Q. DOES APS CURRENTLY HAVE PLANS FOR MAKING ADDITIONS OR IMPROVEMENTS TO ITS ENVIRONMENTAL CONTROLS?

A. Yes, the Company intends to achieve emission reductions in an integrated, coordinated manner, on a schedule that coincides with planned unit outages. APS currently has extensive plans to install additional technology in its Cholla Power Plant in the upcoming years. The Company has projected that additional or improved environmental controls for the Cholla Power Plant will cost approximately $135 million over the next several years. These capital expenditures will result in substantial environmental benefits for APS customers, as well as the citizens of Arizona. Attachment EZF-1 sets forth the environmental projects scheduled for the Cholla Power Plants. Additional projects at the Four Corners and Navajo Power Plants may be necessary and/or desirable in the coming years.

Q. IS THE COMPANY REQUESTING RECOVERY OF ANY OF THESE PROJECTS IN THIS CASE?

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[7] 40 C.F.R. § 50.1 *et seq.*; 42 U.S.C. § 7409.

A. Yes. The APS EIC Plan (Attachment EZF-1) sets out the planned environmental projects for the Cholla Power Plants. This is the basis of the EIC for which the Company is seeking approval in this filing.

Q. PLEASE SUMMARIZE THE ENVIRONMENTAL LAWS AND REGULATIONS THAT WILL IMPACT THE COMPANY'S CAPITAL INVESTMENT REQUIREMENTS.

A. The Clean Air Act established air quality standards for various air pollutants. Coal-fired power plants are subject to numerous regulatory requirements under the Act. The primary focus of these requirements is the reduction of SO_2 and NOx emissions, particulate matter, volatile organic compounds and heavy metals, including mercury.

The EPA has revised the New Source Review ("NSR") rule under the Clean Air Act.[8] NSR is a pre-construction permitting program that governs air pollutant emissions from new sources and existing industrial sources that undergo "major modifications." NSR requires the installation of state-of-the-art emissions control technology to reduce emissions. "Routine Maintenance, Repair and Replacement" ("RMRR") activities are excluded from the scope of the NSR program. For existing facilities, NSR has resulted in a set of complex and controversial regulations, particularly related to the RMRR exclusion. Since 2002, EPA has been undertaking efforts to reform its NSR program, including the issuance of two final rule packages and one proposal intended to streamline and simplify the NSR program requirements and applicability determinations. The RMRR rules are currently the subject of litigation.

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[8] 40 C.F.R. §§ 51.161-166, 52.21; 42 U.S.C. § 7411.

The new EPA Clean Air Mercury Rule ("Mercury Rule"),[9] issued in March 2005, established performance standards to limit mercury emissions from existing and new coal-fired plants. The purpose of the rule is to reduce utility emissions of mercury by 69%, from 48 to 38 tons in 2010, and to further reduce to 15 tons per year by 2018. Pursuant to the EPA's market-based trading program, each state is assigned a "budget" for reducing mercury emissions from coal-fired power plants, and must submit a compliance plan to the EPA. Each generation unit within the state will be assigned a certain number of "allowances," and the generation unit operator must hold adequate allowances to offset each generation unit's emissions, starting in 2010. Those emission credit allocations will be further reduced starting in 2018.

The EPA recently promulgated the Clean Air Visibility rule,[10] which establishes presumptive SO_2 and NOx emission levels, known as "presumptive BART" levels, for electric generating units. It is the responsibility of the states to implement the rule and determine what emission controls are needed at each generating plant. Additional capital expenditures may be required for the Company to comply with the rule's presumptive BART requirements. In addition, the rule requires steady and continuing emission reductions through 2064. To assure continuing improvement in visibility to natural lands, the Company anticipates continuing plant improvements and capital investments.

Q. ARE THERE OTHER ANTICIPATED LEGISLATIVE MANDATES THAT MAY REQUIRE IMPROVED ENVIRONMENTAL CONTROLS?

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[9] 40 C.F.R. §§ 60.24, 45Da-50Da; 40 C.F.R. §§ 60.4101 *et seq.*

[10] 40 C.F.R. §§ 51.302, 308; *see also*, 42 U.S.C. § 7491-7492.

A. Yes. The Clear Skies Act is federal legislation currently pending before Congress that could require further environmental controls to comply with its proposed standards. The provisions of the Clear Skies Act, as currently proposed, would further require that SO_2, NOx, and mercury emissions to be reduced significantly.[11]

Q. WHAT IS THE COMPANY'S CURRENT STRATEGY TO REDUCE EMISSIONS?

A. APS has decided to implement an extensive emissions reduction project at its Cholla Power Plant. APS plans to implement a number of different Pollution Control Projects at that plant over the next several years.[12] See APS EIC Plan, Attachment EZF-1.

Q. IS APS CONSIDERING REDUCING EMISSIONS AT ITS GENERATING PLANTS BEYOND CURRENT REGULATORY STANDARDS?

A. Yes. As an energy supplier and producer, we are subject to environmental regulations on the federal, state, county and local levels. In addition, the Four Corners Power Plant works with the Navajo Nation Environmental Protection Agency to address certain environmental issues. APS strives to perform beyond mere compliance in all areas of our business. The Company believes it is prudent to address environmental compliance issues in a proactive manner, to ensure the continuing protection of Arizona's environment. Additionally, it is our experience that the costs of these technology installations will increase after the

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[11] Clear Skies Act, S. 131 109th Cong. (2005).

[12] In September 2005, APS submitted information to ADEQ to incorporate this voluntary emissions reduction project into Cholla's Title V permit renewal. Supplemental Information to a Title V Air Quality Permit Application for Class I Permit #1000108 Renewal, prepared by Arizona Public Service Company for the Cholla Power Plant (September 28,2005).

new laws go into effect, making it more cost effective to address these environmental changes sooner, rather than later. Another consideration is the fact that regulatory agencies and/or environmental groups have sued several electric utilities in an effort to compel further emission reductions. The current litigation efforts make it clear that emission reduction is a significant issue.

Q. ARE APS' CONCERNS REGARDING THE COST OF ENVIRONMENTAL CHANGES UNIQUE?

A. No. In 2004, the National Association of Regulatory Utility Commissioners, in conjunction with the National Association of State Energy Officials and the Environmental Council of States, conducted a comprehensive study to examine the approach in the states and/or incentives utilized to improve the environmental performance of base-load electricity generation facilities ("NARUC Study").[13] The NARUC Study acknowledged that whatever the regulatory path the state and federal officials choose for improving the environmental performance of these generating facilities, it was clear that future emission limits would be more stringent.[14] In the study, the lack of regulatory certainty and high implementation costs were identified as major barriers that hinder companies from making investments to improve environmental performance.[15]

Q. DO OTHER STATES PROVIDE FOR STREAMLINED RECOVERY OR PREFERENTIAL REGULATORY TREATMENT FOR EXPENDITURES TO IMPROVE ENVIRONMENTAL CONTROLS?

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[13] *A Survey of State Incentives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities; Policy and Regulatory Initiatives;* The National Association of Regulatory Utility Commissioners (June 2004).

[14] *Id. at 5.*

[15] *d. at 17.*

A. Yes. The NARUC Study found that a number of states have developed environmental cost recovery programs for improving the environmental performance of base-load electricity generation facilities.

Q. PLEASE PROVIDE EXAMPLES OF THESE STATE PROGRAMS.

A. Florida passed statutes that authorize the Florida Public Service Commission ("PSC") to allow the recovery of a utility's prudently incurred environmental compliance costs through a cost-recovery factor that is separate and apart from the utility's base rates. The PSC makes its determination based on projected environmental compliance costs that are required by environmental laws or regulations.[16] The Florida Legislature specifically stated that the statutory provisions were to be liberally construed to protect the public welfare.[17]

Indiana has enacted statutes that provide for cost recovery of pollution control equipment installed to comply with the requirements of the Clean Air Act Amendments of 1990.[18] The General Assembly had found that the growth of Indiana's population and economic base had created a need for new energy generating facilities in the state; and that the development of a robust and diverse portfolio of energy generating capacity, including the use of renewable energy resources, was needed if Indiana was to continue to be successful in attracting new businesses and jobs.[19] The statutes require that the Public Utility Commission approve the estimated cost, the schedule for the development and the implementation of the environmental compliance plan.

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[16] Fla. Stat. § 366.8255 (2005).

[17] Fla. Stat. § 366.01 (2005).

[18] Burns Ind. Code Ann. § 8-1-27 *et seq.* (2004).

[19] Burns Ind. Code Ann. § 8-1-8.8-1 (2005).

West Virginia statutes provide rate incentives for utility investments in clean coal and clean air technology facilities that are located in West Virginia.[20] The statute was enacted to respond to pending U.S. Congressional legislation limiting the emissions of oxides of sulfur and nitrogen from coal-fired plants. Upon a finding that it is in the public interest, the Public Service Commission must authorize ratemaking allowances for electric utility investments in clean coal and clean air technology facilities or electric utility purchases of power from clean coal technology facilities located in West Virginia.[21]

A Kentucky statute allows a regulated utility producing energy from coal to recover costs through a surcharge for complying with certain federal, state and local environmental requirements for coal combustion wastes and the by-products from facilities utilized for the production of energy from coal.[22] The Supreme Court of Kentucky found that the surcharge created a new right for all electric utilities to recover expenses, as well as, a return on and a return of capital costs associated with environmental projects, without filing a general rate case.[23]

Q. WHAT IS THE VALUE OF THE EIC RELATED TO LONG-TERM PLANNING?

A. APS serves one of the fastest growing service territories in the country. APS is projecting that the capital investment necessary to expand its transmission and

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[20] W. Va. Code §24-2-1g (2005).

[21] *Id.*

[22] K.R.S. § 278.183 (2004).

[23] *Kentucky Industrial Utility Customers, Inc., et al. v. Kentucky Public Service Commission*, 983 S.W.2nd 493, 500, 1998 Ky. LEXIS 165 (December 1998).

distribution facilities[24] to serve its native load for 2007 through 2009 will be approximately $1.4 billion. An EIC would provide a means for timely recovery of the costs associated with necessary environmental projects as the projects are progressing.

Q. WHAT IS THE DIFFERENCE BETWEEN AN EIC AND THE SURCHARGE ASSOCIATED WITH THE ENVIRONMENTAL PORTFOLIO STANDARD?

A. The purpose of the surcharge associated with the EPS is to promote the use of renewable resources, such as solar, wind, biomass, hydro and geothermal. These are clean and self-replenishing energy resources that will benefit the citizens of Arizona. In most cases, the technologies for these renewable resources are still developing and costs are higher than conventional generation, making the funding from the EPS surcharge essential to promote these resources. In contrast, the EIC would address the economic realities of upgrading technology for fossil-fuel generation facilities to reduce the amount of emissions. The combination of both approaches – seeking increased use of renewable resources and installing state-of-the-art technology to reduce emissions – should assure that customers have reliable energy resources and that the effects of pollution are minimized.

IV. GREEN POWER OFFERINGS

Q. PLEASE EXPLAIN THE GREEN POWER OFFERINGS THAT THE COMPANY IS PROPOSING.

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[24] Pursuant to Decision No. 67744, the Commission has imposed a self-build moratorium on APS for any generating facility with an in-service date prior to January 1, 2015, unless expressly authorized by the Commission.

A. In light of the growing variety of renewable resources that are becoming available, APS believes that customers should have the opportunity to utilize those energy resources. Our proposed offerings, the Green Power Block Schedule and the Green Power Percentage Schedule, will offer our customers a variety of renewable resources at a more affordable price than an exclusive solar offering. Mr. DeLizio provides a detailed explanation of these new schedules in his testimony.

Q. HAVE CUSTOMERS EXPRESSED AN INTEREST IN GREEN POWER?

A. Yes. Some of APS' customers wish to subscribe to specific percentages of renewables in their energy purchases. For example, the US Green Building Council has a Leadership Energy and Environmental Design ("LEED") program of which renewable energy resources is an important component. The LEED program is a voluntary, consensus-based national standard for developing high-performance, sustainable buildings and is rapidly gaining interest in Arizona and across the country. Under this program, customers who obtain a portion of their energy from green power can claim LEED "points", which count toward overall LEED certification. In addition, Arizona Governor Napolitano has issued an executive order (Executive Order 2005-05) mandating that new state facilities derive at least 10% of their energy from renewable sources, and that requires new state facilities be LEED-certified. The Arizona Department of Administration has already approached APS to discuss how to meet that objective. The 10% option in Green Power Percentage Schedule does just that.

Q. WILL APS PROVIDE RENEWABLE ENERGY FOR THE SPECIFIC AMOUNTS THAT CUSTOMERS SUBSCRIBE?

A. Yes. Renewable energy in the amount desired by Green Power customers will be available in the APS system from our existing portfolio in the subscribed amount. APS will limit subscription to this rate to the renewable energy that can be actually supplied to the APS system. APS will use the revenue from these Green Power offerings to procure additional renewable energy in the future.

Q. HOW WAS THE AMOUNT OF THE GREEN POWER PREMIUM CALCULATED?

A. At the current stage of our renewable portfolio, the determination of a Green Power premium is not a straightforward task. APS has very good information on solar energy production but limited information on other resources, even though we expect our non-solar resources to grow substantially in coming years. APS also has done extensive research on market rates for renewable energy but this dynamic, developing industry is often difficult to predict. Instead of attempting to project exactly what our technology and price mix will be, we have taken a more direct approach by examining the recent discussions about the EPS rules that are currently pending before the Commission. The Company has been very involved in the process for the proposed EPS rules and believes that those proposed rules provide a reasonable framework for calculating our new Green Power premium. Therefore, the Green Power premium of $0.03/kWh was computed by dividing the amount of renewable energy required by proposed EPS standard from 2006 through 2015 by the potential revenue that would be provided by the proposed EPS surcharge over the same period. Although we are well aware that the standard is not final and may change, we believe this approach is reasonable. We should note that the rate basis will be reevaluated in coming years as our portfolio grows, and APS may request an adjustment of this premium in a future proceeding.

Q. HOW DOES THE GREEN POWER SCHEDULE WORK IN CONJUNCTION WITH THE EPS SURCHARGE THAT IS CURRENTLY COLLECTED FROM CUSTOMERS?

A. The money collected from the Green Power schedules will be in addition to the Commission-mandated EPS surcharge. The renewable energy purchased for the Green Power customers will be purchased in conjunction with the EPS energy requirement; therefore, the projected $.03/kWh average premium cost to meet the portfolio standard is the appropriate cost upon which to base the Green Power schedules.

Q. HOW WILL THE GREEN POWER OFFERINGS WORK WITH THE EXISTING SOLAR PARTNERS OFFERING?

A. APS is proposing to freeze the Solar Partners rate and now offer the Green Power rate that can utilize all renewable energy sources. Existing Solar Partner customers would be allowed to either remain on that rate, or transfer to the Green Power rate.

Q. HOW WILL CUSTOMERS BENEFIT FROM THE NEW GREEN POWER OFFERINGS?

A. The new Green Power offerings expand the variety of renewable energy options offered to customers, at a more affordable rate. Under the Solar Partners tariff, customers may purchase a 15 kWh block of solar energy for $2.64 (or $0.18 per kWh), as contrasted with the Green Power offerings where the premium is $0.03 per kWh. The two options provided will also allow customers to choose their participation level based on their own renewable energy objectives and economic abilities.

V. <u>NET METERING PROPOSAL</u>

Q. WHY IS THE COMPANY PROPOSING A NET METERING RATE SCHEDULE?

A. Net metering is a means to encourage the installation and utilization of small renewable resources by offering customers the opportunity to provide their excess generation to the Company as an offset to their energy usage.

Q. PLEASE EXPLAIN THE COMPANY'S NET METERING PROPOSAL.

A. Under the Company's net metering pilot proposal, residential and small commercial customers that have renewable energy resource facilities of 10 kW or less will have the opportunity to provide excess energy to the Company. The amount of excess energy that is provided to the APS electric grid will be credited back to the customer in subsequent months. The Company's proposal is capped at 15MW; the term of the pilot project is three years. At the end of the three years, no additional customers will have the opportunity to participate, however, those customers already on the Net Metering rate schedule will be allowed to continue on it. Mr. DeLizio discusses this Rate Schedule in his testimony.

Q. WILL THE COMPANY CONTINUE TO OFFER ITS EPS CREDIT PURCHASE PROGRAM IN CONJUNCTION WITH THE NET METERING PROPOSAL?

A. Yes, for the term of the pilot program, the Company will allow customers to participate in both the EPS Credit Purchase Program, which provides a specified payment for the installation of solar equipment, and in net metering, which compensates customers for the excess generation from renewable resource generators. These act as incentives to encourage customers to invest in and install renewable resources on their homes and small businesses. Whether to continue with these significant incentives will be reexamined in conjunction with other federal and state incentives at the end of the pilot program.

VI. ENVIRONMENTAL PORTFOLIO STANDARD

Q. WHAT IS THE COMPANY'S POSITION RELATED TO THE ENVIRONMENTAL PORTFOLIO STANDARD?

A. The Company believes that renewable resources are an important part of Arizona's energy future. APS has supported the EPS since it was first adopted in 2001. APS was the first utility in the state to offer a green energy option (APS Solar Partners program). In addition, APS has had signed agreements with third parties for construction and generation of 18 megawatts of biomass and wind projects. APS has worked extensively on developing other projects including additional wind and biogas projects. Unfortunately, none of these projects, except the biomass project, have been delivered.

APS has participated in the numerous workshops sponsored by the Commission related to EPS. Draft proposed rules are currently under consideration. I believe that everyone recognizes that there is a premium associated with the purchase of renewables; therefore, it is critical that the funding for the EPS be sufficient to meet the renewable resource requirements.

Q. IS THE COMPANY REQUESTING ADDITIONAL FUNDING TO COMPLY WITH THE PROPOSED RULES?

A. The Company is raising the issue now because changes to the proposed rules may impact the funding necessary to comply with the EPS. In Decision No. 67744, the Commission established an adjustment mechanism to allow for specific Commission-approved changes to APS' EPS funding outside of a rate case. If the Commission finalizes new EPS rules that require increased funding, APS will petition the Commission to increase its EPS surcharge.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A

Statement of Qualifications
Edward Z. Fox

Ed Fox is Vice President for Communications, Environment and Safety at Arizona Public Service Company (APS). In this capacity, Mr. Fox is responsible for all external and internal communications, as well as environmental, health and safety compliance. He is the responsible officer for Corporate Security and facility and real estate management, and he also oversees the Environmental Portfolio Standard and the company's Technology Development group that identifies and helps develop technologies, such as solar energy and fuel cells, for integration into the APS system.

Fox is an attorney and the former Director of the Arizona Department of Environmental Quality (ADEQ) where he served the State from 1991 to 1995. Prior to coming to Arizona in 1985, he was an Assistant Attorney General in West Virginia. From 1985 to 1991, Mr. Fox was in private practice in Phoenix and Tucson, Arizona, where he represented business clients on state, federal and local environmental and commercial matters.

Fox received his J. D. from the West Virginia University. He holds a Masters in Public Administration and a B.A. from the American University in Washington, D.C.

Fox has provided leadership for numerous organizations and initiatives. For example: he chaired the State Trust Land Reform Committee and the Arizona Department of Environmental Quality's Air Quality Cap and Trade Committee, which looked to develop market mechanisms to help improve air quality in the Valley; he served as a member of the Governor's Brown Cloud Committee; and, he chaired a sub committee of the Governor's Growing Smarter Committee. Mr. Fox was chair of the ASU Morrison Institute for Public Policy from 1999-2002; he currently chairs the Arizona Zoological Society dba The Phoenix Zoo; and he serves on the Executive Committee of Valley Partnership.

Mr. Fox is currently associated with the following organizations: ASU Morrison Institute, Arizona Zoological Society, Valley of the Sun United Way, Arizona Town Hall, ASU Council for Design Excellence, and Maricopa Partnership for Arts and Culture.

APS EIC Plan

Generation Unit	Project	Start Date	Complete Date	Purpose	Requirement - Effective Date	Capital Dollars	O&M Dollars
Unit 1, Cholla	Install baghouse	2004	2007	Decrease PM & Hg, Increase visibility (Opacity)	NAAQS/EPA Clean Air Hg Rule - 2007	$22M	$0.6M
Unit 1, Cholla	Install low NOx burner system	2006	2007	Decrease NOx, ozone	RAVI/RH BART/ NAAQS - 2013	$4.3M	0
Unit 1, Cholla	Upgrade scrubber	2005	2007	Decrease SO2	RAVI/RH BART Class 1 Areas/ NAAQS - 2013	$5M	$0.1M
Unit 2, Cholla	Install low NOx burner system	2004	2008	Decrease NOx, ozone	RAVI/RH BART/ NAAQS - 2013	$6M	0
Unit 3, Cholla	Install low NOx burner system	2008	2009	Decrease NOx, ozone	RAVI/RH BART/ NAAQS - 2013	$5.6M	0
Unit 3, Cholla	Install baghouse	2006	2009	Decrease PM & Hg, Increase visibility (Opacity)	NAAQS/EPA Clean Air Hg Rule - 2010	$45M	$0.9M
Unit 3, Cholla	Scrubber - SO2 absorber	2006	2009	Decrease NOx, ozone	RAVI/RH BART/ NAAQS - 2013	$47M	$4.6M

RAVI = reasonably attributable visibility impairment
RH = regional haze
BART = Best Available Retrofit Technology
NAAQS = National Ambient Air Quality Standards
SCR = selective catalytic reduction
Hg = mercury
PM = particulate matter

REBUTTAL TESTIMONY OF EDWARD Z. FOX

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

1873658.19

EXHIBIT

APS 35

Admitted

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REBUTTAL TESTIMONY OF EDWARD Z. FOX
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Edward Z. Fox, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes. I filed Direct Testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of various Arizona Corporation Commission ("ACC" or "Commission") Staff and intervenor witnesses relating to the implementation of the Environmental Improvement Charge ("EIC"), and the proposed adjustment mechanism that would provide for the timely recovery of the cost associated with the substantial capital investment necessary for adding and improving environmental controls. I will also provide updated cost estimates for the projects that are currently planned to comply with existing and future federal and state laws, regulations and policies, as well as describe those additional projects, which were not included in my direct testimony.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In my rebuttal testimony, I respond to Staff and Intervenor opposition based upon their assertions that the EIC is unique and violates the traditional ratemaking

process. As such, I describe why APS believes that the EIC is appropriate and describe the benefits that Arizona will see as a result. To put the benefits into context, I identify the relevant environmental standards that APS will be required to meet and the connection between such standards and the environmental projects proposed. In relation to such standards, I discuss why pollution control projects should be pursued sooner rather than later and why traditional ratemaking treatment to recover such expenses is not sufficient.

Next, I identify the currently planned projects addressing conventional pollutants at the Cholla plant and the estimated costs that APS will seek recovery for through the EIC. Finally, I identify the types of costs that should be subsequently recoverable through the EIC, including costs associated with addressing greenhouse gas emission and future improvements at the Four Corners and Navajo Power Plants.

III. ENACTMENT OF THE EIC DOES NOT VIOLATE THE COMMISSION'S TRADITIONAL RATEMAKING PROCESS.

Q. SEVERAL PARTIES OPPOSE EIC AS A CONCEPT BECAUSE IT FALLS OUTSIDE TRADITIONAL RATEMAKING. DO YOU AGREE?

A. No. According to the direct testimony of Kevin Higgins on behalf of Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition, a mechanism like the EIC can be considered by the Commission if it determines that there is a "compelling public interest" to do so.[1] We agree this is the correct test and, as discussed below, APS believes that there is a compelling public interest to enact a mechanism designed to expedite pollution control in a cost effective manner.

[1] (Kevin C. Higgins (KCH), p18, line 11.)

Q. WHAT ARE THE MAJOR CONCERNS OF OTHER PARTIES THAT OPPOSE THE EIC?

A. Staff opposed the EIC because it appears to be unique and the environmental impacts for implementing the EIC are unclear. In addition, Staff has concerns that the EIC seeks to recover estimated future costs for projects not yet mandated.[2]

Q. DOES APS AGREE WITH STAFF'S POSITION?

A. No. This Commission, through its past decisions, 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.

Q. COULD YOU PLEASE EXPLAIN?

A. The Commission has approved surcharges to encourage use of renewable energy as well as to implement demand side management programs. More recently, the Commission has authorized the use of a surcharge mechanism to recover the cost of arsenic remediation. Each of these programs has a significant environmental benefit. And, we believe the Commission should give the same consideration to emissions reduction and air pollution remediation and authorize APS to implement a surcharge that aggressively reduces the pollutants associated with the generation of low cost power. The environmental benefits of the proposed EIC are discussed below on Pages 12 and 13 of this testimony.

Q. TO SUPPORT THEIR RECOMMENDATION THAT THE EIC NOT BE ENACTED, STAFF CITES AN INCOMPLETE STUDY CONDUCTED BY CAMBRIDGE ENERGY RESEARCH ASSOCIATES ("CERA)". IS SUCH A COMPARISON APPROPRIATE?

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[2] (Matthew J. Rowell, p. i).

A. No. Staff acknowledges that the study is incomplete.[3] Furthermore, Staff does not cite any specific provision of the study, but instead relies upon representations made by CERA to conclude that either no surcharges for environmental improvements to coal plants are allowed or if they are, those surcharges are designed to recover expenses "actually incurred."[4] We anticipate that the Commission will see the benefit to continuing its longstanding commitment to protecting the environment by allowing APS to implement a surcharge mechanism that will allow it to proactively and aggressively confront environmental concerns.

Q. STAFF ALSO CITED THE NARUC STUDY[5] OF STATE INCENTIVES REFERENCED IN YOUR DIRECT TESTIMONY. SPECIFICALLY, STAFF IDENTIFIES THE STATE OF WISCONSIN AS BEING INNOVATIVE IN THE AREA OF FINANCING ENVIRONMENTAL IMPROVEMENTS TO SUPPORT THE USE OF BONDS AS AN ALTERNATIVE TO EIC FINANCING. IS SUCH A COMPARISON APPROPRIATE?

A. No. Wisconsin has promulgated Act 152 entitled, "Financing of Environmental Improvements to Energy Utility Facilities." The Act creates a mechanism by which bonds would be issued by the Wisconsin Public Service Commission, to be repaid from revenues collected from fees paid by customers.[6] The Act specifies that the environmental trust bonds are not a debt of the state and do not impose any financial obligation on the state or its political subdivision.[7]

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[3] (Matthew J. Rowell, p7, line 25).

[4] (Matthew J. Rowell, p7-8, lines 20-26, 1-12).

[5] *A Survey of State Initiatives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities; Policy and Regulatory Initiatives;* The National Association of Regulatory Utility Commissioners (June 2004).

[6] 2003 Wisconsin Act 152.

[7] *Id.*

Q. DOES ARIZONA HAVE ANYTHING EQUIVALENT TO WISCONSIN?

A. No. Arizona has no specific bonding authority for addressing pollution at energy utilities. In fact, Arizona's bonding authority is based upon federal law which in 1986 specifically deleted air pollution projects from eligibility. Thus Arizona has no bonding capacity or program available to address the projects APS needs to implement.

Q. DO YOU HAVE OTHER CONCERNS ABOUT STAFF'S ANALYSIS OF THE NARUC STUDY?

A. Yes. Although Staff cites the inapposite example of Wisconsin, Staff was silent in its analysis of the environmental cost recovery programs discussed in my Direct Testimony, including the states of Florida, Indiana, West Virginia and Kentucky. Although the programs are not identical to EIC, they provide a mechanism for recovery for programs that improve environmental performance. For example, Florida passed a statute that authorizes recovery of prudently incurred environmental compliance costs through a cost-recovery factor, separate from a rate case. Indiana has enacted a statute that requires the Public Utility Commission to approve the estimated cost schedule for development and implementation of an environmental compliance plan. West Virginia provides rate incentives for utility investments in clean coal and clean air technology facilities. Finally, Kentucky allows a regulated utility producing energy from coal to recover costs through a surcharge for complying with certain federal, state and local environmental requirements related to the production of energy through coal.

Q. STAFF SUGGESTS THE USE OF ENVIRONMENTAL BONDS TO FINANCE THE PROPOSED PROJECTS. HAS APS LOOKED INTO THIS OPTION?

A. Yes. According to Goldman Sachs[8], air pollution control facilities, which include facilities that control or abate air pollution by removing, altering, storing or disposing of the pollutants, do not qualify for tax exempt bond financing unless they started construction prior to 1985. That is why APS' recent pollution bonding efforts only include the refinancing of older air pollution projects.

Q. DOES ANY OTHER PARTY OPPOSE THE EIC?

A. Yes. The Residential Utility Consumer Office ("RUCO") opposes the EIC, because in its opinion, the EIC violates the normal ratemaking process which requires a plant to be actually built (known and measurable) and in-service (used and useful) prior to being given ratemaking consideration in the context of a rate case. To support this proposition, RUCO states: "Even in the case of the U.S. Environmental Protection Agency ("EPA") arsenic mandate, the Commission has continued to require that the plant actually be in-service prior to allowing the arsenic surcharge to be collected."[9]

Q. DO YOU AGREE WITH RUCO'S ANALYSIS?

A. No. In Decision No. 67163 (August 10, 2004), the Commission approved Mountain Glen Water Service Company's arsenic surcharge to repay a loan issued by the Water Infrastructure Financing Authority ("WIFA") to fund arsenic remediation. Staff's recommendations, adopted in Decision No. 67163, stated as follows:

> [T]hat the arsenic surcharge mechanism described above would become effective with the Company's first billing cycle four months after the closing of the WIFA loan, the surcharge would be shown as a separate line item on the customer bills as an "arsenic surcharge," and that the debt service component of the surcharge

[8] "Development of Tax-Exempt Financing" Presentation to APS, September 7, 2005.

[9] Direct Testimony of Marylee Diaz Cortez, p 36, footnote 4).

> collection would be deposited in a separate interest-bearing account and disbursements from the account would be made only for arsenic treatment capital expenditures associated with servicing the WIFA loan.

There was no requirement that regulatory assets be in service prior to the enactment of the surcharge.

Q. ARE YOU AWARE OF ANY OTHER CASES IN WHICH THE COMMISSION AUTHORIZED SURCHARGES PRIOR TO HAVING COSTS ACTUALLY INCURRED?

A. Yes. In Decision No. 68858 (July 28, 2006), Arizona-American Water Company requested inclusion of post-test year fire flow projects in rate base to encourage improvement in public fire safety and to minimize deferral costs to future periods.[10] Staff recommended approval because, in part, the projects would protect customers' lives and properties.[11] By approving the recovery of the fire flow improvement costs through an alternative fire flow surcharge, the Commission agreed with Staff and also reasoned that the improvements were for the health and safety of the ratepayers.[12]

IV. ENACTMENT OF THE EIC IS GOOD PUBLIC POLICY

Q. WHY DOES APS BELIEVE THAT THE EIC IS APPROPRIATE?

A. By almost any measure, the electric utility industry is in a transition with regard to future fuels and generation technologies, a transition toward cleaner-burning fuels and cleaner more efficient technologies. Whether it relates to conventional pollutants like SO_2, NO_x and particulates, or climate change, this transition is being driven by concerns about the impacts of fossil fuel generation on public health and the environment. In fact, during the past 15 years the Commission has

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[10] Decision 68858 at 6.

[11] *Id* At 7.

[12] *Id at 11.*

held workshops to discuss the costs of these impacts. Often called "externalities," the issue is how to account for the costs of pollution from fossil plants that are not controlled under existing regulations. The EIC is an appropriate mechanism to begin to address these concerns.

Any future resource plan to provide the needed electricity for APS' rapidly growing customer base will require not only the inclusion of new resources, but also the sustaining of our existing generating plants. These new resources, both renewables under the current Environmental Portfolio Standard ("EPS") rules or the proposed Renewable Energy Standard & Tariff ("REST") rules, and new conventional generation, will all be significantly cleaner than today's generation.

While renewables and other new technologies are inherently cleaner, the lingering question remains, "What do we do with existing generation?" This question is of great importance because the existing fleet of fossil generation is critical to navigating the transition in a cost effective manner. APS' fleet of coal units range from 26 to 44 years old. They represent 49% of our power generation and produce electricity at less than 2 cents per kWh. Other than the Palo Verde Nuclear Generating Station ("PVNGS"), these are the most cost effective units in the APS fleet. They have many years of operating life left, but they are older technologies with older pollution control equipment.

As APS manages the transition to cleaner, more efficient generation in the future, it is incontrovertible that the existing fossil fleet must be maintained both for its reliability and cost effectiveness. If, however, the future demands cleaner generation, which APS believes to be true, then the existing fleet (the fleet that will keep the electricity flowing during the transition) must be as clean as reasonably practical. We believe that for the existing fossil generation, the EIC is

the corollary to the EPS and proposed REST. It is a program that creates an incentive for APS to make its existing fleet of fossil generation as clean as practical.

Q. SHOULD APS WAIT UNTIL NEW ENVIRONMENTAL REGULATIONS ARE ACTUALLY PROMULGATED?

A. No. Since the early 1970s, environmental laws in the United States have become increasingly stringent. As the science regarding the health and environmental impacts of pollution has evolved and emission control technologies become more cost-effective, emission limits for facilities like utility generating units have become increasingly stringent. Today, we are on the verge of another wave of new, more stringent standards for the so-called "criteria pollutants" (including SO_2, NO_x, and particulates). The utility industry also faces the first-ever regulation for the pollutant mercury, and the growing trend to regulate greenhouse gas ("GHG") emissions that contribute to climate change.

For many pollutants, the science and technology to control the pollutants is well known long before the political process results in a final regulatory program. More often than not, the delays to implementing a final program are the result of special interest legal and political challenges. It is rare, however, for these challenges to actually stop a program once it has been proposed.

Q. DO YOU HAVE ANY EXAMPLES?

A. Yes. One example of this delay is the Grand Canyon Visibility Transport Commission ("GCVTC"). Established in the 1990 Clean Air Act Amendments, the GCVTC was created to propose how to reduce visibility impairment in National Parks and wilderness areas in the western United States. After nearly

five years of work, a Citizens Advisory Group appointed by 9 western governors, comprised of all the stakeholders, including utilities, environmental groups, Native American representatives and others, unanimously recommended a program to improve visibility in the West. Ten years later, that program has not been implemented because of lawsuits and political challenges by special interest groups. In the meantime, the program to reduce SO_2 and NO_x to help improve visibility, which is well known and understood, has not been implemented.

APS believes that if we understand the science and the need to control pollutants, and if the technology is commercially available to achieve the emission reductions, it is good public policy to consider taking early action to control those pollutants.

Q. WHY ISN'T THE TRADITIONAL RATEMAKING PROCESS SUFFICIENT TO RECOVER COSTS ASSOCIATED WITH ENVIRONMENTAL EXPENDITURES?

A. Under traditional rulemaking, utilities incur expenses and then, after the fact, seek recovery and a rate of return. The standard for review is whether the expenditure is prudent. Historically, this process has been a major obstacle to proactively addressing concerns such as the environment. If the pollution control was not absolutely required, utilities faced a potential negative prudency decision, thereby creating a disincentive to taking early action.

Q. WHY SHOULD THE ACC ALLOW SUCH COSTS TO BE RECOVERED IF THE SPECIFIC PROJECTS ARE NOT YET REQUIRED?

A. The measure by which the ACC should determine the appropriateness of the EIC is whether it is in the public interest. It is hard to posit that reducing pollution is not in the public interest.

Arizona has been in the vanguard on many environmental issues over the past 25

years. The 1980 Arizona Groundwater Management Act and the 1995 Aquifer Pollution Protection Program were ground-breaking when first proposed. The ACC has also shown its leadership in concern for environmental impacts of decisions under its jurisdiction, including the EPS rules, which led the nation on renewables when first proposed.

While the EIC may be unique in construction, there is nothing unique about Arizona and the ACC breaking new ground to achieve a sound public policy. Establishing a program, like the EIC, that creates an incentive for utilities to control pollution to the greatest extent practical is good public policy and is in the public interest.

Q. ARE THERE OTHER REASONS THAT IT IS APPROPRIATE TO EXPEND MONIES ON MANDATES THAT ARE NOT YET IN EFFECT?

A. Yes. APS believes that it is prudent to expend monies on pollution control projects for several reasons: to minimize its environmental risk; to meet future regulatory requirements, and to protect and enhance the health and welfare of the citizens of Arizona and our environment.

Over the past several years, numerous other utilities have been sued by EPA or environmental groups in an effort to force emission reductions. Based upon conversations with EPA and various environmental groups, APS has good reason to believe that by voluntarily committing to make reductions, APS has avoided protracted and expensive litigation that may well have resulted in a settlement agreement to install these same controls and possibly impose fines and penalties.

In addition, almost all of these projects will be required in the future to meet regulatory requirements. The proposed Clear Skies legislation was intended to amend the Clean Air Act to consolidate in one place all emission reductions

required under the Act and in accordance with a new schedule. Because Congress did not pass that proposal, EPA began implementing multiple regulatory programs under the existing Clean Air Act. For example, the mandates to reduce SO_2, NO_x, PM, and mercury are currently in place, including the federal and proposed state mercury rules, the regional haze rules, and the state opacity standards.

The lead time on newly mandated requirements is dependent on the mandate; however, typically these types of projects take several years to complete. APS believes it is appropriate to be in compliance before a mandate is effective rather than wait until the last minute.

Additionally, we know from the simple rules of supply and demand that waiting until a time closer to the mandated compliance will drive up costs as other companies compete for the technology, equipment and labor to do the capital improvements. By doing the projects before the increased demand, APS will avoid the run up in costs driven by the increased demand.

Q. WHAT ENVIRONMENTAL BENEFIT WILL ARIZONA SEE AS A RESULT OF THE EIC?

A. Under the EIC, as currently proposed, APS will be retrofitting baghouses on Cholla Units 1 and 3, upgrading SO_2 controls on Unit 1, retrofitting SO_2 controls on Unit 3, and retrofitting Low NO_x Burners on all three Units owned by APS.[13] These projects will significantly reduce SO_2, NO_x, mercury, and particulate matter emissions from the plant. The attached charts[14] show the projected emission reductions of these pollutants. For example, annual SO_2 emissions will decline

[13] There are four units at Cholla. Unit 4, which is also being retrofitted with controls, is owned, and the retrofits will be paid, by PacifiCorp.

[14] See Attachment EZF-1RB.

from 32,475 tons in 2007 to 5,148 tons in 2010 and beyond. Those reductions are expected to help protect visibility in nearby Class I areas (protected by Clean Air Act Section 169A), as well as contribute to lowering ambient fine particle concentrations. These reductions will result in significant public benefit and similar beneficial effects are expected from reductions in other pollutants.

Q. WHAT TYPE OF EXPENDITURES IS APS SEEKING TO RECOVER THROUGH THE EIC?

A. APS is committed to securing our existing fleet of fossil fuel units for the long-term benefit of our customers and to making sure that these units comply with all environmental requirements. The process for implementing government environmental mandates often takes many years, even after the science is understood. Where emission reductions or pollution control activities are needed to protect the environment and public health, APS anticipates recovery through the EIC, including those costs necessary for complying with existing laws and anticipated future requirements. APS believes this proactive approach is in the best interests of our customers and Arizona.

V. <u>EIC FUNDING FOR PROPOSED PROJECTS</u>

Q. IF THE PROPOSED EIC INCLUDES ACTUAL AND FORECASTED COSTS, HOW WILL THE COMMISSION BE ASSURED THAT THE IMPLEMENTED EIC WOULD RECOVER ONLY ACTUAL COSTS OF PROJECTS, AS SUCH COSTS ARE INCURRED?

A. While the proposed EIC rate per kilowatt hour is calculated on actual and forecasted costs, an annual true-up mechanism between dollars collected through the EIC and the actual costs of these capital projects will assure the Commission that only actual costs associated with these capital projects will be recovered.

Q. REGARDING YOUR WORKPAPER EZF-WP9, HAVE THE ESTIMATES RELATED TO THE PROJECTED ANNUAL CAPITAL EXPENDITURES

CHANGED SINCE THE JANUARY FILING OF THE COMPANY'S APPLICATION?

A. Yes, the estimates for these seven EIC projects have changed from the figures shown in Work Paper EZF-WP9. The estimates for five of these projects have changed slightly, and are now based upon detailed engineering and supplier bids. The estimates for the other two projects (Unit 3 Scrubber and Unit 3 Baghouse) are currently still preliminary estimates, but have increased significantly (approximately 25%) based upon contractor bids received on similar projects for Unit 4. The detailed estimates for these projects are planned to be developed over the next six to nine months. This is the normal progression for developing estimates for capital projects, beginning with conceptual engineering and estimates to a preliminary phase to detailed engineering and estimates, with final costs determined by actual contractor bids. Additional insights into the costs of the projects became apparent during negotiations with an EPC (engineer, procure and construct) contractor for the scope and costs of the scrubber and fabric filter project. In addition, at the time of my pre-filed testimony in January 2006, the scope of the projects was in the early stage of development when the costs estimates were prepared. Since that time, additional engineering has been completed, and cost estimates reflect the more refined scope of the project.

Q. BASED UPON THE DETAILED ENGINEERING AND SUPPLIER BIDS, WHAT IS THE PROJECTED COST OF THE NEEDED CAPITAL EXPENDITURES?

A. The estimated costs currently are approximately $160 million,[15] as compared to the $135 million shown in EZF-WP 9. In addition, since the filing of my January 2006 testimony, the Company has determined that additional environmental

[15] See Attachment EZF-3RB

improvement projects beyond the seven projects set out in my workpapers will be mandated in the near future. Specifically, there are six additional projects that APS requests be included in the EIC.[16] As set forth in the rebuttal testimony of Mr. DeLizio, the EIC charge will be recalculated to show the impact of these updated costs, as well as the additional costs and the additional projects. The update of the $160 million in capital expenditure includes only mandated requirements. Of course, any amounts collected under the EIC will be subject to later true up once actual capital expenditures have been incurred.

Q. PLEASE DESCRIBE THE SIX ADDITIONAL PROJECTS.

A. The six additional projects all relate to the Cholla plant. The total cost of these additional projects is $83.2 million, broken down as follows: a lime-slaking project at a cost of $10.5 million; a slurry disposal project at a cost of $3 million; and carbon-injection for Units 1, 2 and 3, at a combined cost of $7.7 million. In addition, APS is adding a Unit 2 baghouse at a cost of $62 million.

Q. IS APS SEEKING TO RECOVER THE ENTIRE $160 MILLION THROUGH THE EIC AT THIS TIME?

A. No. As set forth in the direct testimony of Greg Delizio, the EIC is designed to recover capital costs on an annual basis as the costs are incurred. For the initial request only, the Company will use an eighteen month period (January 2007 through June 2008) to calculate the EIC.

Q. CAN YOU PLEASE EXPLAIN WHY ADDITIONAL PROJECTS WERE ADDED SINCE THE ORIGINAL APPLICATION WAS FILED?

A. Recently proposed mercury regulations would require the installation of the carbon injection projects for Cholla Units 1 through 3, and the installation of the

[16] See Attachment EZF-4RB.

Unit 2 baghouse project sooner than was previously anticipated. In addition, the need for slurry disposal was discovered during preliminary engineering, not at the time of conceptual engineering, when the projects were originally submitted in this rate case. Finally, the lime-slaking project should have been included in the original submittal, but was inadvertently excluded.

VI. OVERVIEW OF THE ENVIRONMENTAL CHALLENGES FACING APS

Q. WHAT IS THE STATE OF CLIMATE POLICY IN THE UNITED STATES TODAY?

A. There is significant uncertainty surrounding many aspects of climate change policy, including the timing of any mandatory program, the degree of restriction that might be required, and the projected costs of such a program. On the other hand, individual states, cities and regions are taking action, and we believe it is only a matter of time before an Arizona or national program is adopted.

Recently, California passed a mandatory cap on greenhouse gas emissions. And on Sept. 8, 2006, Governor Napolitano signed an Executive Order establishing a statewide goal of reducing future greenhouse emissions to 2000 levels by the year 2020 and 50% below that level by 2040. The Governor left open the possibility of accelerating the 2020 goal to 2012. The Executive Order follows recommendations of the Climate Change Advisory Group, which the governor appointed to come up with proposals for lowering greenhouse gas emissions.

APS believes that a national program is the appropriate way to address this issue because climate change is a global, not a state or even a regional, issue. However, APS recognizes that states like Arizona are moving forward in the absence of a national program. It is therefore imperative to develop incentives to encourage industry to make early reductions to carbon emissions and/or carbon intensity,

and for regulated utilities to be provided with a process by which expenditures on emission reductions are deemed prudent and recoverable.

Q. HOW DOES APS PROPOSE DEALING WITH THE COSTS OF CLIMATE CHANGE?

A. Climate change is a long-term problem requiring long-term vision and steadfast effort. APS has been at the forefront of utilities that have taken prudent actions to respond to climate change issues, as discussed above. However, to truly offset the emissions associated with meeting growing customer demands will require expenditures that, absent a process like the EIC, have a risk of becoming stranded in future regulatory programs.

Coordinating climate change efforts with our generation forecasting and planning efforts better allows APS to evaluate the potential financial and operating impacts of proposed legislation and regulatory programs. In this context, APS is considering the potential future costs of carbon emissions as a criterion in evaluating our current generation Request for Proposals.

Q. WOULD APS BE ABLE TO RECOVER THE COST OF COMPLYING WITH FUTURE GREENHOUSE GAS EMISSION REGULATIONS THROUGH THE EIC?

A. Yes. While the current proposed plan addresses only conventional pollutants and mercury, the proposed EIC is broad enough to allow other environmental costs, such as those that might be incurred addressing greenhouse gas emission or complying with future climate change regulations.

Q. WHAT EFFORTS HAVE BEEN MADE TO ANALYZE THE RISKS OF GREEN HOUSE GAS ON APS' OPERATIONS?

A. With respect to historic action on this issue, the Company is aware of the "stranded asset" risk and is making efforts to preserve the value of early GHG

efforts to the extent possible, including ongoing monitoring and evaluating of evolving GHG reporting programs and registries. Over the past several years, several utilities have published reports outlining their GHG and other air pollutant emissions and assessing their risks from future GHG regulations. These companies include AEP, Cinergy, TXU, Southern, DTE Energy, and Progress Energy. APS is working on an analysis of greenhouse gas risks.

Q. COULD YOU DESCRIBE APS' RESPONSE TO THE ISSUE OF CLIMATE CHANGE AS RAISED BY DAVE BERRY OF WESTERN RESOURCE ADVOCATES?

A. APS has been engaged with climate change issues for over a decade. In 1994, APS was one of the signatories to the U.S. Department of Energy's ("DOE") Climate Challenge Program, in which APS committed to maintain system-wide GHG emissions, including CO_2, (tons) below 1990 levels and to achieve that goal by the year 2000. APS met its commitment, primarily through improved performance and capacity at PVNGS.

Over time, however, APS' customer growth and increased electricity demand have resulted in an increase in the overall company CO_2 emissions. APS has had to increase generation to meet this demand, and beginning in 2000, APS' system-wide emissions began to climb above the 1990 level. While obtaining the generation needed to meet customer demand resulted in actual tons of CO_2 exceeding the 1990 levels, the Company did focus its resource acquisition on fuel sources (natural gas rather than coal) that created a less intense impact on CO_2 emissions (lbs/MWH). This means APS has become more efficient at providing electricity to our customers, with fewer CO_2 emissions per megawatt-hour generated. This "climate efficiency" trend is projected to continue through 2012, primarily through increased use of gas-fired plants, renewable energy sources,

energy efficiency programs, DSM[17], our partnership with EPA to reduce atmospheric releases of SF6, use of plant by-products (ash) for cement manufacturing, and planting trees to sequester CO_2.

Recently, APS committed to this trend in its 2005-2010 Business Plan. The Company has set a goal of reducing carbon intensity at its power plants by 10 percent by 2010 from the baseline year 2000. This goal is particularly noteworthy in light of the Company's rapidly increasing customer base.

Recognizing APS' past and current actions to minimize GHG emissions, the U.S. EPA selected APS from among all the utility companies in the country to receive its 2006 Climate Protection Award.

Q. WHAT OTHER ENVIRONMENTAL CHALLENGES DOES APS FACE?

A. In the late 1990's, the EPA commenced a national enforcement initiative targeting electric utilities, pursuant to the Clean Air Act's New Source Review and Prevention of Significant Deterioration (collectively "NSR") program. EPA began its enforcement initiative by sending Clean Air Act Section 114 requests for information to numerous coal-fired power plants in the country requesting detailed reports on historical emissions of sulfur/nitrogen oxides and particulate matter and pollution control projects undertaken at the plants since the mid-1970s. EPA reviewed company responses and, in some cases, issued additional Section 114 information requests. EPA also initiated settlement negotiations with some companies, including Salt River Project (relating to operations at the Coronado Generating Station).

APS received Section 114 requests for information in July 2000 for its Cholla and

[17] See Attachment EZF-2RB.

Four Corners Power Plants and submitted responses in September 2000. Notably, APS has not received any follow-up requests from EPA.

After reviewing the various Section 114 responses, the EPA filed a number of lawsuits against coal-fired power plants alleging NSR violations. Several of these companies, including Tampa Electric Company, PSEG Fossil LLC, Virginia Electric and Power Company, Southern Indiana Gas and Electric Company and others, have settled the lawsuits and agreed to pay large penalties in addition to retrofitting pollution control equipment. A few companies have chosen to fight the lawsuits, and the litigation continues in various courts, including the United States Supreme Court.

Q. DOES APS FACE ENFORCEMENT RISKS FROM EPA?

A. Yes. While APS is in compliance with Federal, State and local environmental laws and has Environmental Systems in place to ensure compliance, it is a fact that not all the rules are absolutely clear and, indeed, the EPA and States periodically change their interpretation of existing rules, thus creating risk for all utilities.

EPA's NSR enforcement initiative, referenced above, is based upon a new interpretation concerning which "modifications" at coal plants trigger NSR. Under NSR, utilities that make major modifications to their units that result in a significant net increase in emissions are required to treat the unit as if it were new, including installing state-of-the-art pollution control equipment that would not otherwise be required. Although EPA did not formally announce its new interpretation of which changes triggered NSR, EPA's position became clear in its NSR enforcement initiative. The new interpretation relates to which changes constitute "routine maintenance, repair and replacement" and are thus exempt

from NSR. The litigation also involves a dispute regarding how to calculate whether a significant emissions increase has occurred.

The extent of this regulatory uncertainty is highlighted by the fact that several courts have adopted radically different interpretations of the NSR program. For example, the Seventh Circuit Court of Appeals (in the *Cinergy* case) agreed with EPA's interpretation of NSR. By contrast, the Fourth Circuit Court of Appeals (in the *Duke* case) agreed with the utility industry's interpretation of NSR. This regulatory uncertainty provides strong incentive for the utility industry to proactively implement measures to reduce emissions and thereby reduce its enforcement risk, to the extent possible.

Q. ARE THERE OTHER LITIGATION RISKS KNOWN TO APS?

A. Yes. Several environmental groups have also filed citizen suits against coal plants alleging various violations of the Clean Air Act, with the intent of forcing those plants to add pollution control equipment. The suits involving power plants at Hayden in Colorado, Mohave in Nevada, and San Juan Generating Station in New Mexico, among others, resulted in settlements requiring significant upgrades.

Q. HAVE THE EPA, ADEQ OR ENVIRONMENTAL GROUPS PURSUED LITIGATION AGAINST APS?

A. No. Starting in late 1990s, prior to the initial set of NSR lawsuits and the enforcement initiative, APS initiated a dialogue with several environmental interest groups relating to pollutant emissions from APS' coal-fired plants. The goal of this initial dialogue was to determine whether there was any concern with environmental performance at APS' coal plants. Based upon the favorable initial discussions and after commencement of the EPA enforcement initiative, the dialogue was expanded to include EPA and ADEQ. These discussions resulted in

a plan to implement enhanced pollution controls at the Cholla plant. The emission control projects included in the EIC are a direct result of those discussions. The plan has concurrence from state and federal agencies (ADEQ, EPA, and the National Park Service). Based upon discussions with EPA personnel and the environmental groups, APS believes that the regulatory agencies did not pursue enforcement against Cholla because of our dialogue with these agencies and the environmental organizations, and our commitment to new, enhanced controls.

Although APS' discussions with the environmental groups and agencies involved projects at Cholla that were not yet legally mandated, APS fully recognized that such controls would indeed be required in the future. In an effort to minimize its environmental risk, and in anticipation of impending regulatory requirements to reduce emissions, APS elected to implement the projects earlier than would otherwise be required. APS' commitment to these projects is a prudent approach to environmental compliance and risk management: APS' early commitment to the projects very likely kept APS from being sued, and these projects will be required to meet future environmental standards.

VII. ENVIRONMENTAL STANDARDS

Q. PLEASE DESCRIBE THE RELEVANT ENVIRONMENTAL STANDARDS AND PROPOSED PROJECTS THAT APS WILL BE IMPLEMENTING WITH THE PROPOSED EIC CHARGE.

A. The EPA's Clean Air Visibility Rule ("CAVR") will be implemented in Arizona through the Regional Haze State Implementation Plan ("SIP") being prepared by ADEQ. Under that SIP, due to EPA by 2007, irrespective of whether ADEQ follows Regional Haze Rule 40 CFR § 51.308 or § 51.309, Cholla Units 2 and 3 will be expected to reduce SO_2 and NO_x emissions to Best Available Retrofit Technology ("BART") levels or, depending on which program ADEQ adopts,

acquire "allowances" to offset its emissions. Because there is no certainty that a viable allowance market will exist, APS has no choice but to reduce emissions from those units. Cholla plans to comply with the SIP requirements before the anticipated Regional Haze SIP deadline of 2013. The proposed changes will enable the units to significantly reduce emissions and meet the presumptive BART limits.

In addition, Cholla's Acid Rain (SO_2) program allowances under Phase II of the Clean Air Act Acid Rain Program will be reduced in 2010. The scrubber additions and changes will ensure program compliance with these requirements. The addition of the Unit 1 fabric filter will ensure compliance with the new Arizona SIP requirement of 20% opacity.

Arizona will also submit a SIP to implement the EPA's Clean Air Mercury Rule ("CAMR") by November 2006. Based on discussions with ADEQ and a review of ADEQ's draft mercury rules, published in the *Arizona Register* on August 11, 2006, the SIP is expected to include more stringent mercury control requirements than those in the CAMR, and will require compliance with Phase 2 requirements much sooner (by 2013).

At this time, we know that fabric filters and scrubbers are the first step technology to address mercury control, but it may be necessary to add additional equipment to reach the required mercury emission limits set by the State. This additional equipment is included in our amended request to the Commission.

Specifically, APS is planning to implement the following pollution control projects at the Cholla Power Plant:

- Installation of a baghouse on Unit 1 in order to meet the State of

Arizona's new 20% opacity limitation. This limitation became effective in April 2006, and Cholla obtained a compliance schedule in its air permit that affords it time to construct the new baghouse.

- Installation of baghouses on all units (including baghouse on Unit 1 described above) in order to meet the State of Arizona's anticipated mercury rules. Although it is uncertain what the ADEQ will require in its final mercury rules (which have been drafted but not yet finalized), Arizona will be required to meet its allocated mercury emissions budget beginning in 2010, and ADEQ is expected to require at least 90% mercury removal by 2013. At a minimum, baghouses will be required to meet this removal efficiency.
- Installation of SO_2 absorbers on Unit 3 in order to meet the State of Arizona's anticipated regional haze rules, compliance with which must be achieved no later than January 2013. Again, it is uncertain what ADEQ will require in its final regional haze rules (which have not yet been developed), but EPA's regional haze program established "presumptive" control levels, and it is anticipated that any regional haze control determination for Cholla would be similar to EPA's presumptive levels.
- Installation of low NO_x burners on Units 2, 3 and 4 to comply with the State of Arizona's anticipated regional haze rules by 2013. Again, APS will not know with certainty what is required until ADEQ promulgates its final regional haze rules and makes a determination regarding emission control levels for Cholla. However, it is reasonable to expect that low NO_x burners will be required to comply with anticipated NO_x

limits.

- Installation of a SO_2 absorber on Unit 3 and changes to the existing SO_2 absorber on Unit 1 in order to assure compliance with applicable emission limitations.

Q. WHAT PERMITS WERE NECESSARY TO COMMENCE INSTALLATION OF THE ABOVE PLANT CHANGES?

A. In September 2005, APS met with ADEQ and agreed to submit an air permit application to allow the installation of the Unit 1 fabric filter (mandated by new opacity standards) and the scrubber project in 2007, and the Unit 3 fabric filter scrubber in 2009. APS submitted the permit application on September 28, 2005. APS received the final permit on May 3, 2006. APS also submitted a permit application for the low NO_x burners in August 2006.

Q. WERE THERE ANY SUBSEQUENT MODIFICATIONS TO THE PROPOSAL?

A. In January 2006, APS amended the permit application to remove the low NO_x burners from the permit application because it was unable to reach agreement with ADEQ regarding applicable regulatory requirements. In July 2006, ADEQ and APS agreed upon a regulatory approach for the NO_x burner projects, and APS submitted a permit application for the NO_x burner projects in August 2006.

Q. IN YOUR DIRECT TESTIMONY, YOU STATE THAT ADDITIONAL IMPROVEMENTS AT THE FOUR CORNERS AND NAVAJO POWER PLANTS MAY BE NECESSARY AND/OR DESIRABLE IN THE COMING YEARS. CAN YOU EXPLAIN?

A. The EPA has developed a program to regulate regional haze and mercury emissions from power plants, and a number of utilities have been sued to force further emissions reductions. Although the specific levels of controls or reductions that will be required have not yet been finalized, APS is planning

emission control improvement projects based upon anticipated requirements.

Under the regional haze program, EPA has issued "presumptive" control levels for NO_x and SO_2, and it is expected that most power plant units will be required to meet these or similar control levels. (The control levels vary according to the type of boiler, type of coal burned, level of current controls, etc.) EPA is expected to issue final emission requirements for Four Corners and Navajo Generating Station sometime in late 2007 or 2008.

In addition, Federal lawsuits around the country have generally sought (and in several settlements have obtained) control levels that require the installation of the best available control technologies for NO_x control.

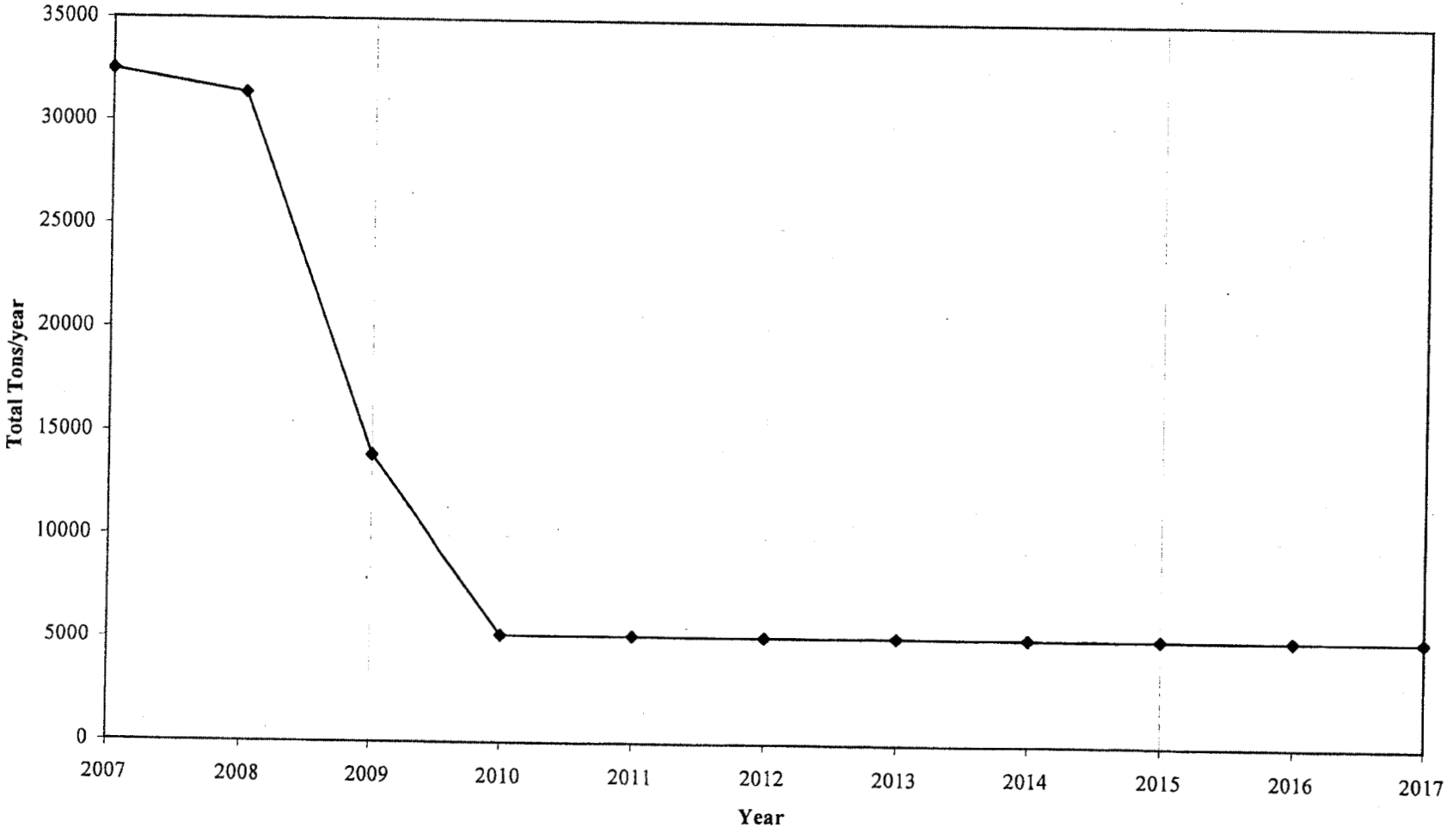
EPA is expected to implement its Clean Air Mercury Rule on the Navajo reservation starting in 2010, and it will apply to Four Corners and Navajo Generating Station. Based on information of current emissions levels, APS may not have to make any significant capital investments to comply with the rule by 2018.

VIII. CONCLUSION

Q. AND DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

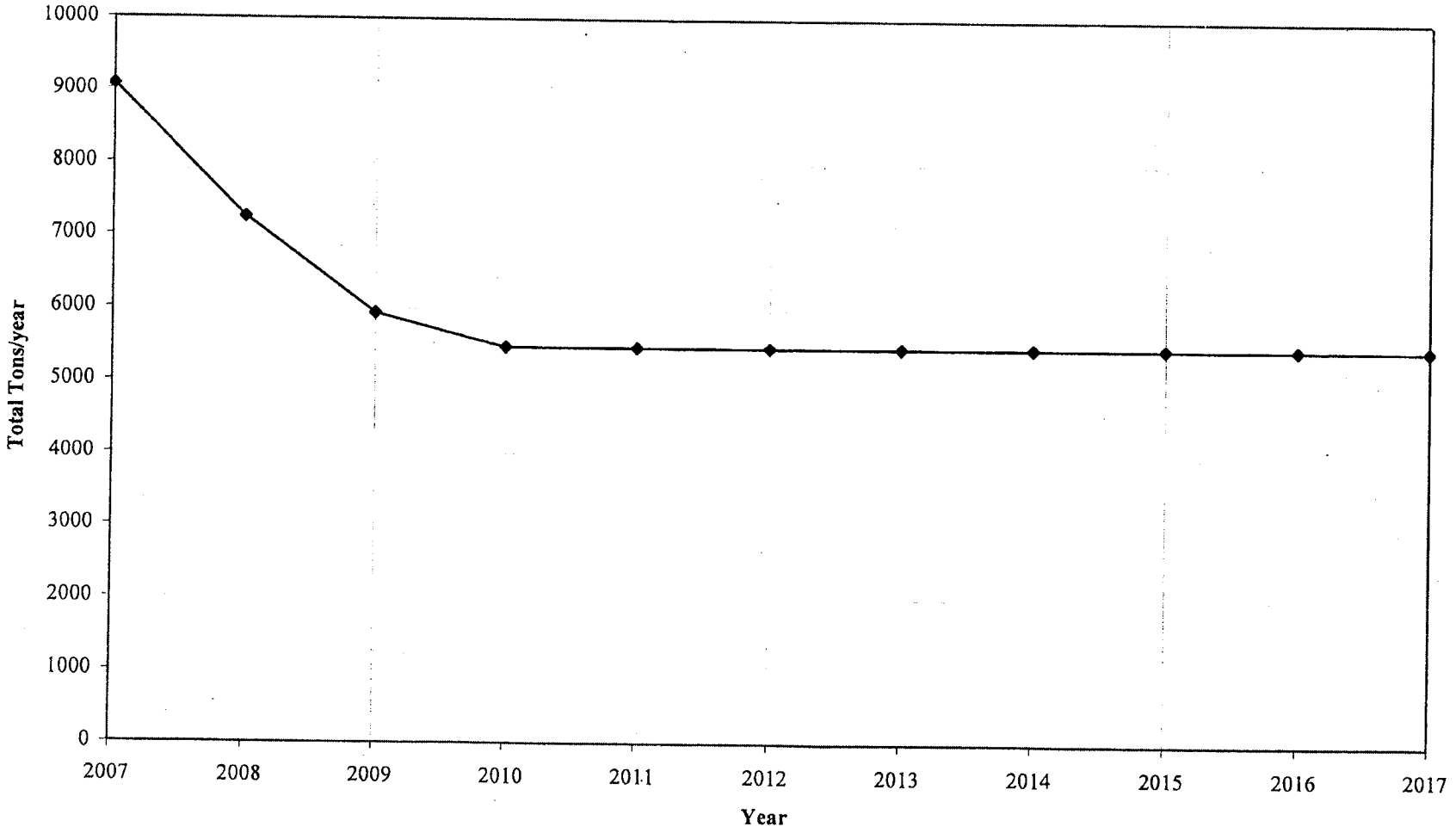
A. Yes.

Projected Emission Reductions
Cholla 1-3 Annual SO2 Emissions (Tons/year)



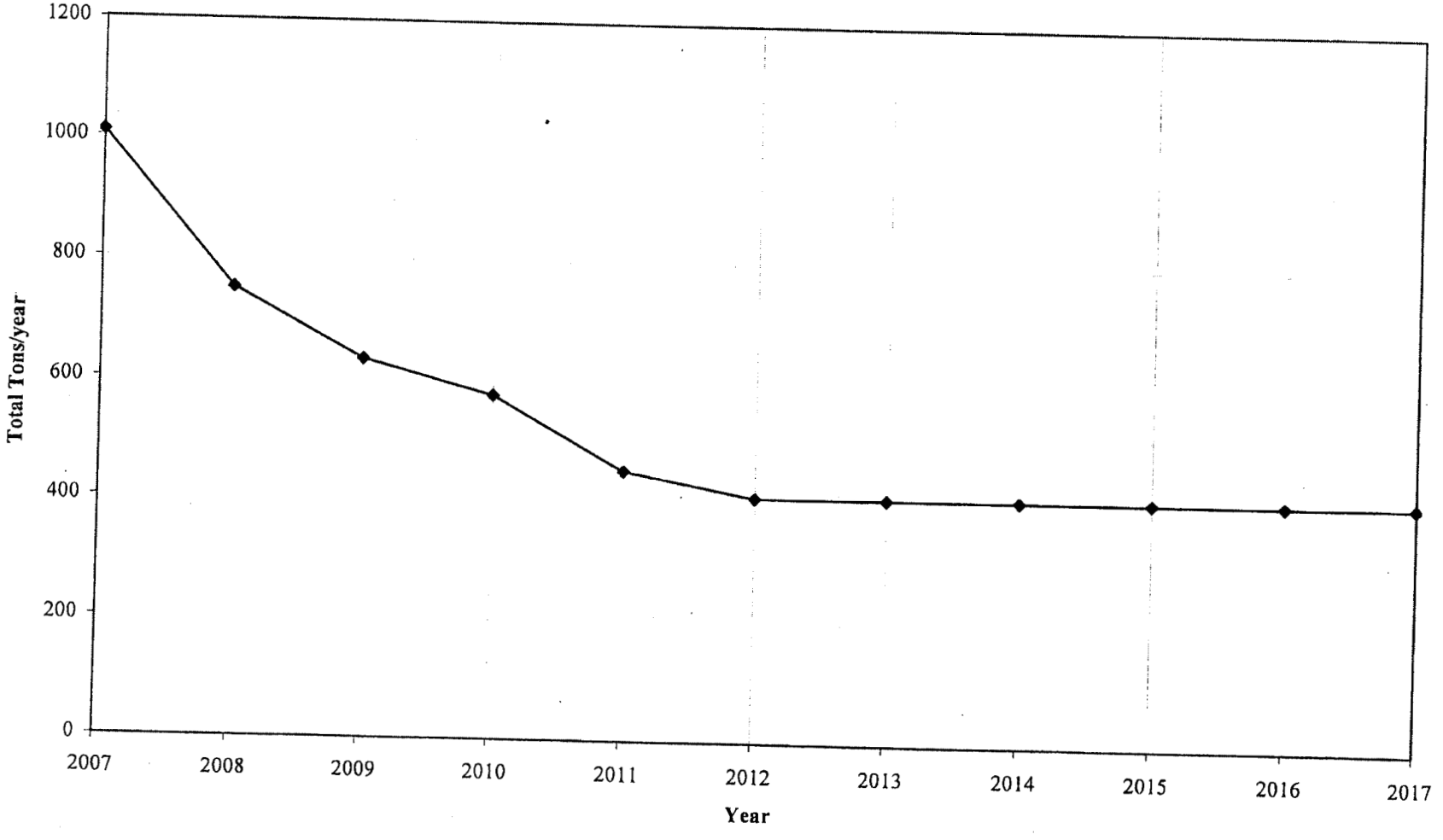
EZF-1RB

Projected Emission Reduction
Cholla 1-3 Annual NOx Emissions (Tons/year)



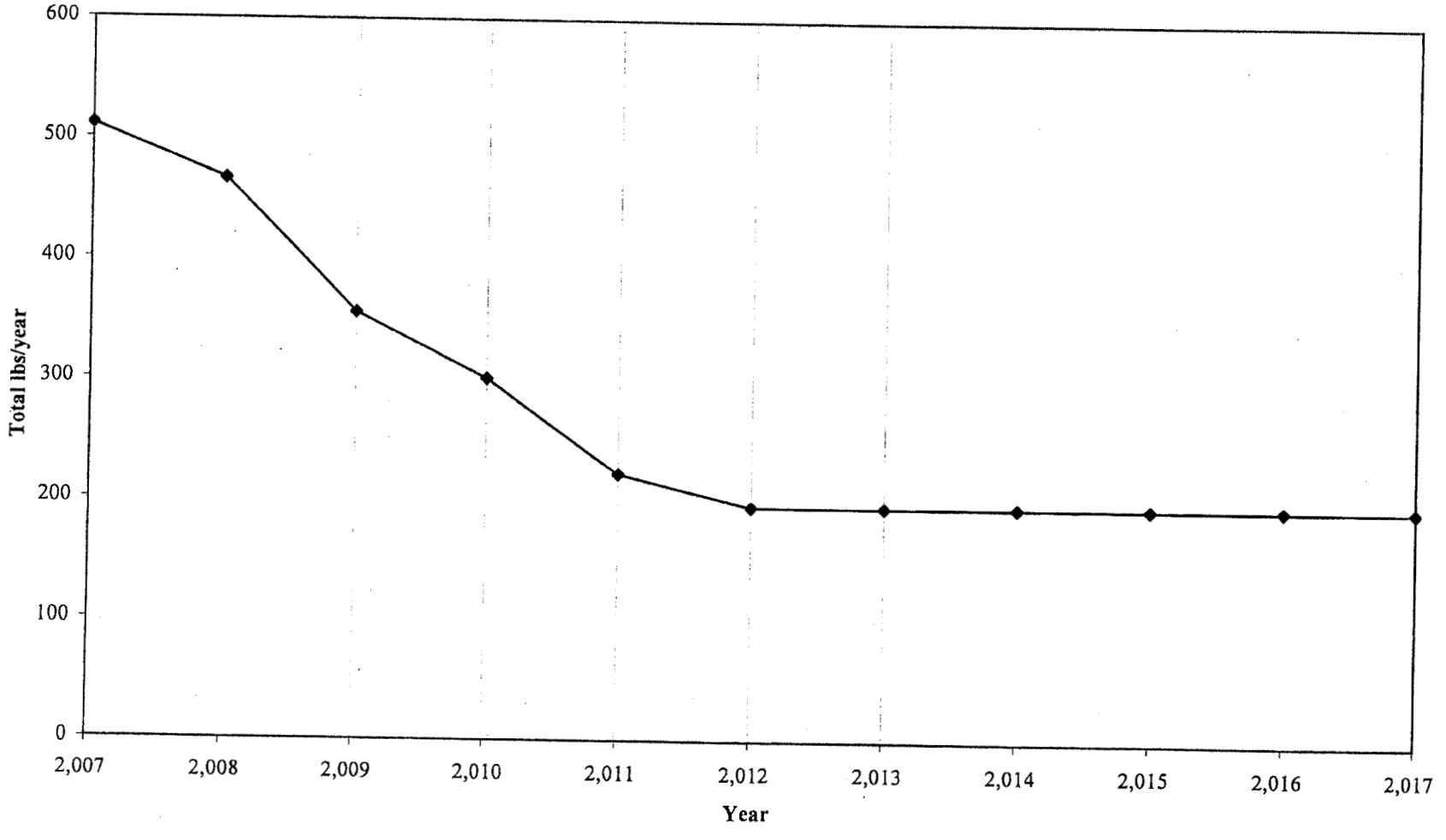
EZF-1RB

Projected Emission Reduction
Cholla 1-3 Annual PM10 Emissions (Tons/year)



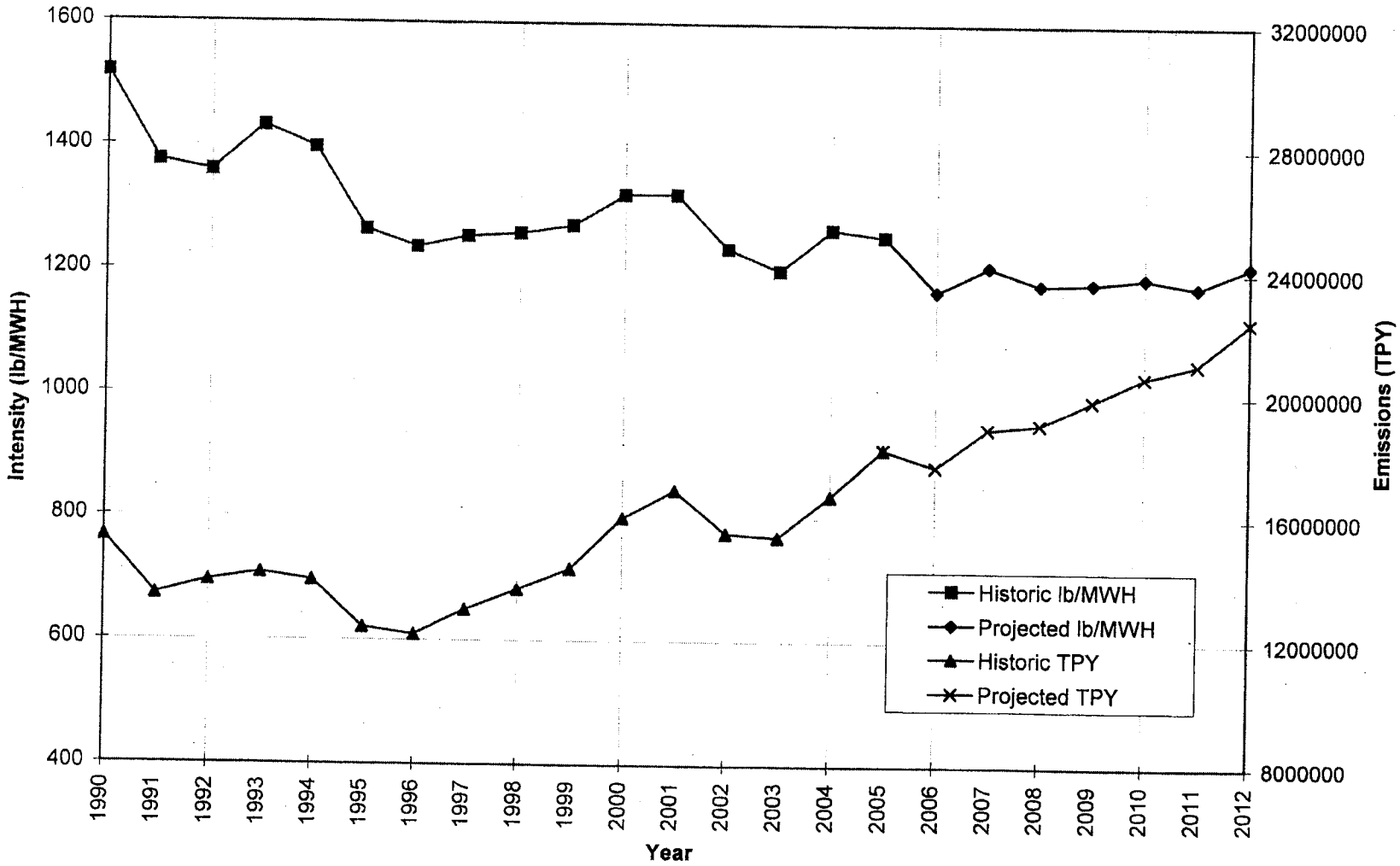
EZF-1RB

Projected Emission Reduction
Cholla 1-3 Annual Hg Emissions (Pounds/year)



EZF-1RB

APS Historic/Projected CO2 Emissions



EZF-2RB

Estimated EIC Project Costs
Environmental Improvement Projects
Updated Projected Annual Capital Expenditures

($ x 1000)

June 2006 Estimate:

Project	In-Service Year	Project Estimate Total	Project Estimate Details	Actuals 2004	Actuals 2005	Actuals Jan-May 2006	Forecast Jun-Dec 2006	Forecast 2007	Forecast 2008	Forecast 2009
Cholla:										
Unit 1 Baghouse	2007	21,718	Attach. 1	374	3,123	3,498	10,382	3,906	435	
Uint 1 Scrubber Upgrade	2007	5,418	Attach. 2		88	97	665	4,498	70	
Unit 1 Low NOx Burners	2007	4,806	Attach. 3			19	485	4,202	100	
Unit 2 Low NOx Burners	2008	6,032	Attach. 4	48	4	12	0	1,438	4,530	
Unit 3 Scrubber	2009	60,500				35	965	18,000	28,000	13,500
Unit 3 Baghouse	2009	56,000				7	493	12,000	26,500	17,000
Unit 3 Low NOx Burners	2009	5,284	Attach. 5			1	3	180	1,400	3,700
Total		159,758		422	3,215	3,669	12,993	44,224	61,035	34,200
						16,662				

Prior Estimate (as shown in EZF_WP9):

Project	Total	2004	2005	2006	2007	2008	2009
Cholla:							
Unit 1 Baghouse	22,129	373	3,147	15,571	3,038		
Uint 1 Scrubber Upgrade	5,011		174	1,873	2,964		
Unit 1 Low NOx Burners	4,350			200	4,150		
Unit 2 Low NOx Burners	5,951	48	3	0	1,400	4,500	
Unit 3 Scrubber	47,000			940	17,860	21,150	7,050
Unit 3 Baghouse	45,000			900	17,100	20,250	6,750
Unit 3 Low NOx Burners	5,600					200	5,400
Total	135,041	421	3,324	19,484	46,512	46,100	19,200

EZF-3RB

Additional EIC Projects
Updated Environmental Improvement Projects
Projected Annual Capital Expenditures

($ x 1000)

June 2006 Estimate:

Project	In-Service Year	Project Estimate Total	Project Estimate Details	Actuals 2004	Actuals 2005	Actuals Jan-May 2006	Forecast Jun-Dec 2006	Forecast 2007	Forecast 2008	Forecast 2009	Forecast 2010	Forecast 2011
Cholla:												
Unit 1 Baghouse	2007	21,718	Attach. 1	374	3,123	3,498	10,382	3,906	435			
Uint 1 Scrubber Upgrade	2007	5,418	Attach. 2		88	97	665	4,498	70			
Unit 1 Low NOx Burners	2007	4,806	Attach. 3			19	485	4,202	100			
Unit 2 Low NOx Burners	2008	6,032	Attach. 4	48	4	12	0	1,438	4,530			
Unit 3 Scrubber	2009	60,500				35	965	18,000	28,000	13,500		
Unit 3 Baghouse	2009	56,000				7	493	12,000	26,500	17,000		
Unit 3 Low NOx Burners	2009	5,284	Attach. 5			1	3	180	1,400	3,700		
Total		**159,758**		**422**	**3,215**	**3,669**	**12,993**	**44,224**	**61,035**	**34,200**		
						16,662						

Additional Projects:

Project	In-Service Year	Project Estimate Total	Project Estimate Details	Actuals 2004	Actuals 2005	Actuals Jan-May 2006	Forecast Jun-Dec 2006	Forecast 2007	Forecast 2008	Forecast 2009	Forecast 2010	Forecast 2011
Cholla:												
Lime Slaking Upgrade	2008	10,500			1	96	903	8,500	1,000			
Slurry Disposal	2008	3,000					100	2,000	900			
Unit 1 Carbon Injection	2009	1,500						100	400	1,000		
Unit 3 Carbon Injection	2009	3,000							1,000	2,000		
Unit 2 Baghouse	2011	62,000							700	13,400	29,600	18,300
Unit 2 Carbon Injection	2011	3,200								250	2,400	550
Added Projects Total		**83,200**			**1**	**96**	**1,003**	**10,600**	**4,000**	**16,650**	**32,000**	**18,850**
Grand Total		**242,958**		**422**	**3,216**	**3,765**	**13,996**	**54,824**	**65,035**	**50,850**	**32,000**	**18,850**
						17,761						

EZF-4RB

SCHEDULE A - Update
Overview of APS 2005 Advertising Expenses & 2006 Projections
FERC 913.0

Description	FERC 913.0 2005 Cost	Original 2006 Budget	Projected Year-end 2006 APS Costs	Projected 2007* Advertising Costs
Sports Sponsorships:	$3,734,589	$3,810,385	--	--
Advertising payroll, materials & expenses	$ 312,996	$ 325,000	$ 322,415	$ 331,833
Advertising Media & Production				$2,652,000
Energy Conservation Campaign	$ 378,444	$ 500,000	$ 729,385	--
E-3 Spanish Radio	--	--	$ 50,000	--
APS Power Players Print	$ 21,950	$ 25,000		
Television	$1,007,701	$ 899,000	$ 559,282 ($466,069 to promote Energy Cons.)	
Print Newspaper/Magazine	$ 72,218	$ 100,000	--	--
Outdoor (Solar & Renewable Energy)	$ 91,956	$ 100,000	$ 77,663	--
Campaign Development/Production	$1,059,579	$ 318,000	$ 635,670	--
Agency fee	$ 602,283	$ 550,000	$ 600,000	--
Research/Special Projects/Publication Graphics/Industry Relations	$ 192,591*	$ 188,000	$ 5,382	$ 5,382
Subtotal Other Advertising Expenses:	**$3,739,718**	**$3,005,000**	**$2,979,797**	**$2,989,215**
TOTAL:	**$7,474,307**	**$6,815,385**	**$2,979,797**	**$2,989,215**

This listing consists of costs charged to FERC account 913.0, labeled by FERC as "Advertising Expenses (Major only)". Additional advertising expenses not charged to this account and included in the rate case total less than $350,000, including public safety, energy efficient homes and public notice ads.

* 2007 budgets have not been finalized.

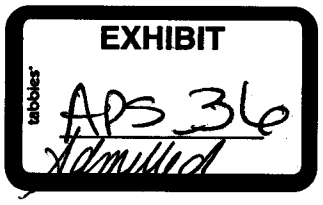


EXHIBIT
APS-37
admitted

DIRECT TESTIMONY OF GREGORY A. DeLIZIO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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SCHEDULE 1 (PROPOSED AND REDLINED) ..... ATTACHMENT GAD-6

SCHEDULE 4 (PROPOSED AND REDLINED) ..... ATTACHMENT GAD-7

DIRECT TESTIMONY OF GREGORY A. DeLIZIO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

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 Supervisor of Regulation and Pricing for Arizona Public Service Company ("APS" or "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 Company is seeking approval of the following: an adjustment mechanism that would provide for timely recovery of investments in environmental improvements to generation facilities; a number of new offerings related to renewable resources; and changes to the Company's current service schedules, as described below. The purpose of my testimony is to address these items. I explain the Company's proposed Environmental Improvement Charge ("EIC") and how it will be administrated. I will also describe three of the Company's new proposals which address renewable resources and net metering; specifically, the Green Power Schedules GPS-1 and GPS-2, and Renewable Resources EPR-5. Additionally, I will discuss the Company's proposed changes to Schedule 1 – "Terms and Conditions for Standard Offer and Direct Access Services" and

Schedule 4 – "Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service."

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony explains the methodology for the proposed EIC, which would allow the Company to implement planned environmental improvements and recover the costs of these capital projects on an annual basis, as the costs are incurred. The EIC initial charge would be set at $0.000152/kWh and be effective with customer bills rendered after January 1, 2007 (the date that it is anticipated the new rates from this rate application will be effective). I also address the proposed Green Power offerings: the Green Power Block Schedule GPS-1 and the Green Power Percent Schedule GPS-2. These offerings allow customers to obtain power from a variety of renewable resources at a lower cost than stand-alone solar power. The Company is also presenting a proposal for net metering (Rates for Renewable Resources EPR-5). This is a pilot program for renewable resource generation facilities that will provide the customer who owns renewable resource generators with a per kilowatt-hour kWh credit for the excess generation that they provide to the APS electric grid. Finally, the Company is requesting modifications to Schedule 1, the Terms and Conditions for Standard Offer and Direct Access Services, and to Schedule 4, Totalized Metering of Multiple Meters at a Single Site. These modifications will simplify the service schedules and clarify how various service charges are applied to specific situations that commonly affect APS customers.

III. SCHEDULE EIC – ENVIRONMENTAL IMPROVEMENT CHARGE

Q. PLEASE PROVIDE AN OVERVIEW OF THE ENVIRONMENTAL IMPROVEMENT CHARGE THAT THE COMPANY IS PROPOSING.

A. APS is recommending that the Commission establish an adjustment mechanism that would reduce regulatory lag by allowing the Company to recover the costs of environmental improvement projects that require substantial capital investments on an annual basis. The proposed EIC would yield an energy-based $/kWh charge that would be assessed to all retail kWh sold by APS. Mr. Edward Fox explains the environmental expenditures forecast for APS over the next several years in his testimony. My testimony describes the technical function of the EIC.

Q. HOW DOES THE EIC REDUCE REGULATORY LAG?

A. Under traditional cost recovery, a utility does not collect revenue related to a particular investment until the Commission issues an order within the context of a rate case. Inevitably there is a delay, often a significant delay, between the construction expenditures and an issuance of a Commission rate order. That regulatory lag prevents the timely recovery of cost associated with even those investments that are the result of government mandates. Thus, the goal in designing the EIC was to reduce this regulatory lag on environmental investments, while maintaining a vehicle for appropriate regulatory review of such investments. See Schedule EIC (Attachment GAD-1) and the EIC Plan of Administration (Attachment GAD-2).

Q. WHAT KINDS OF COSTS WOULD BE INCLUDED IN THE EIC?

A. APS would forecast environmental improvement expenditures on an annual basis. Those expenditures would include costs associated with investment, and

the expenses of installing and maintaining the environmental upgrades at APS' generation facilities. These would include, but not be limited to, the return on capital, depreciation, operation and maintenance expenses, property taxes, and associated income taxes.

Q. WOULD THE COMMISSION REVIEW THE APS EIC PLAN FOR WHICH THESE EXPENDITURES WOULD BE MADE?

A. Yes. As described in Mr. Fox's testimony, the Company has filed its initial APS EIC Plan for which it is seeking approval in this proceeding. In addition, as I discuss later in my testimony, the Company will true-up and file modifications to the plan with the corresponding EIC on an annual basis.

Q. HOW WILL THE EIC BE CALCULATED?

A. On an on-going basis, the EIC is based on applicable EIC revenue components divided by the forecast estimated retail sales over the 12 months period that the rate will be in effect. For this initial request only, the Company has used an eighteen month period (January 2007 – June 2008) to calculate the EIC.

Q. WILL THE EIC APPLY TO ALL CUSTOMERS?

A. The EIC ($/kWh) would be applied to all kWh used by Standard Offer customers. However, customers subscribed to Schedule SP-1 (Solar Partners), or who would subscribe to the proposed Schedule GPS-1 (Green Power Block) or GPS-2 (Green Power Percent) already pay the EIC under their standard rate schedule, so these customers would not be assessed the EIC a second time. Customers subscribed to Schedule Solar-2 will not be paying EIC because those customers have a stand-alone solar electric system that is not connected to the Company's distribution system.

Q. DOES THE COMPANY HAVE A PROPOSAL FOR THE PROCESS TO OBTAIN COMMISSION APPROVAL OF THE EIC ON AN ON-GOING BASIS?

A. Yes, the Company is proposing the following procedure for Commission review of the EIC:

- The Company EIC request for approval and true-up would be prepared on an annual basis.
- The Company would project the anticipated costs for the environmental improvement projects and file them with the Commission by March 15 of every year. As part of that filing, the Company would also true-up the EIC revenues that had been approved by the Commission and collected the previous year, by providing actual data of the costs and EIC revenues recalculated with actual historical data from the previous year.
- Staff would review the proposal, seek clarification or additional information from the Company as needed, and prepare a Staff Report with recommendations regarding the proposed EIC. Staff would file such a report within 60 days of the Company's filing.
- The Commission would consider the Company's EIC filing in an Open Meeting within 30 days of the Staff report filing. If the Commission fails to take action within this time period, the EIC filing and corresponding rate would be deemed approved, subject to true-up the following year.

Q. IS THE COMPANY REQUESTING APPROVAL OF A SPECIFIC EIC IN THIS FILING?

A. Yes. The Company currently has several major environmental improvement projects planned or under construction for its Cholla Power Plant, as discussed

by Mr. Fox and set out in the APS EIC Plan, which is attached to his testimony. In this filing, the Company is seeking approval for inclusion of those environmental projects in the initial EIC.

Q. WHAT FACTORS DID THE COMPANY USE TO CALCULATE THE ESTIMATED EIC ADJUSTMENT?

A. To compute the EIC requested in this filing, we have used components that are consistent with the cost-of-capital, depreciation, property tax and income tax assumptions used in this general rate case filing. Therefore, the debt component of 45.5% and the equity component of 54.5% and the Company's proposed equity cost of 11.5% were used in calculating the requested EIC. Property tax rates specific to the Cholla Power Plant are included, and the environmental assets are depreciated over 25 years. However, should projects qualify as a Certified Pollution Control Facility as provided for under the Federal Energy Act of 2005, amortization may be based on a lesser period.

Q. WILL THE COMPANY TRUE–UP THE EIC FROM FORECASTED DATA TO ACTUAL?

A. Yes, because forecast sales and estimated environmental compliance costs are used for EIC, a true-up mechanism is necessary to adjust for any over or under recovery. Any over or under revenue recovery relative to sales and expense projections will accrue interest, which will be reflected in the annual true-up process.

Q. HOW WILL THE EIC BE IMPACTED BY A GENERAL RATE CASE?

A. As a result of a rate case, the EIC would likely be reduced. This is because the environmental improvements placed in service would become part of rate base

as a result of the Commission order issued in the rate case and therefore would be removed from the EIC.

Q. HOW MUCH IS THE EIC AND WHAT IS ITS EFFECT ON CUSTOMERS' BILLS?

A. The Company is requesting an initial EIC of $0.000152/kWh, which would be effective with bills rendered after January 1, 2007. The average impact on total Company retail revenues, based on expenditures included in the APS EIC Plan for 2007 is approximately 0.18%. The impact to an average residential customer using 1163 kWh monthly would be to increase the customer's monthly bill by approximately 18¢ in 2007.

IV. PROPOSED GREEN POWER SCHEDULES

Q. PLEASE DISCUSS APS' PROPOSED RENEWABLE ENERGY OR "GREEN POWER" SCHEDULES.

A. The Company is proposing to expand renewable options available to customers by including a variety of renewable resources in its Green Power Block Schedule (GPS-1) and Green Power Percent Schedule (GPS-2) offerings. These schedules are attached as GAD-3 and GAD-4. The renewable energy that is provided under these rate schedules would be limited to those renewable resources that are eligible pursuant to the Environmental Portfolio Standard ("EPS"), A.A.C. R-14-2-1618, including any modifications to that rule over time. The renewable resources include, but are not limited to: solar, biomass, biogas, wind, geothermal, or small hydroelectric power. Making lower-cost renewable options available in addition to solar could significantly reduce the cost to the customer for renewable energy, which could potentially increase renewable resources subscription. With the introduction of these two new Green Power schedules, the Company plans to freeze its Solar Partners Rate Schedule

SP-1. Customers currently served by that schedule may remain on that rate schedule.

Q. BRIEFLY DESCRIBE THE DIFFERENCE IN THE PLANS.

A. The premium for both Green Power schedules is $0.03/kWh, as discussed in Mr. Fox's testimony. Both schedules will provide the customer with additional options to increase the use of renewable resources. The Green Power Block Schedule is modeled on the Solar Partners rate schedule design. However, unlike Solar Partners, Green Power Block Schedule offers the customer renewable sources in addition to solar. Under the Green Power Block Schedule, the customer chooses the number of blocks of renewable energy they desire to consume for each month. Each block is equivalent to 25 kWh of renewable energy; the charge is $0.75 per block. Under this Green Power Schedule, the customer knows in advance exactly how much the renewable energy will cost each month based on the number of blocks for which the customer has contracted. For example, a customer that contracts for two 25 kWh blocks of Green Power would pay $1.50 more per month.

In contrast, under the Green Power Percent Schedule, the customer elects a percentage of usage that will come from renewable sources. The percentage choices under this Schedule are 10%, 30%, 50% and 100%. A higher percentage subscription of renewable energy results in a higher additional monthly charge. Based on the election of a renewable percentage, a specific charge will be added to the customer's energy charges on their bill. For example, if a customer who consumes 1,000 kWh in a month elects 10% Green Power, an additional charge of $3.00 (1000 x 10% x $.03) will be added to the

customer's bill. As a result, the monthly cost for the Green Power Percent Schedule customer will vary based on the customer's usage.

Q. ARE THERE OTHER CONSIDERATIONS THAT THE COMPANY MADE WHEN IT DEVELOPED THE GREEN POWER SCHEDULES?

A. Yes. As discussed in Mr. Fox's testimony, APS is aware that some customers want to purchase a specific percentage of renewable energy. Others may prefer to pay a fixed amount each month for renewable energy. The proposed schedules are intended to address both types of customer requirements. Additionally, the Company is reserving the right to either limit the subscription under these schedules if reasonably priced renewable resources are not available, or to petition the Commission to modify the charges under these schedules to reflect current renewable cost premiums.

V. RATES FOR RENEWABLE RESOURCE FACILITIES

Q. PLEASE PROVIDE AN OVERVIEW OF SCHEDULE EPR-5.

A. This net metering rate schedule is offered as a three year pilot program to customers that have renewable resource generation facilities of 10 kW or less, where the customer's generator(s) and load are located at the same premise. Net metering provides a customer a kWh credit for renewable energy that is generated but not used by the customer, and supplied to APS' distribution grid. Schedule EPR-5 is attached (Attachment GAD-5).

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED SCHEDULE EPR-5.

A. The proposed pilot schedule will be available to those customers with renewable resource generation of 10 kW or less that are also served under a qualifying standard retail rate schedule. Renewable resources eligible to participate in this pilot program include solar and other renewable resources as defined in the

Commission's Environmental Portfolio Standard, A.A.C. R-14-2-1618. Qualifying standard retail rate schedules for service under this pilot program are limited to Rate Schedules E-12, ET-1, ET-2, ECT-1R and ECT-2 for residential customers and Rate Schedules E-32 and E-32TOU for general service customers with a monthly maximum demand of 20kW or less. The Company will install the necessary bidirectional metering to measure power flow both to and from the customer. The Company will have to make changes to the customer information systems, so participation under this schedule is subject to the availability of enhanced metering and billing system upgrades.

Q. WHAT COSTS RELATED TO NET METERING WILL BE FUNDED THROUGH THE EPS SURCHARGE?

A. The incremental cost for net metering will be funded through revenues collected through the current EPS surcharge. In addition, infrastructure costs, such as changes to the customer billing systems, will be funded through the EPS surcharge. Revenue associated with transmission and distribution, as well as non-avoidable costs that are not recovered from EPR-5 customers would also be funded by the EPS surcharge. In other words, EPS will fund all revenues that otherwise would have been collected, excluding fuel.

Q. WHAT HAPPENS IF THE CUSTOMER GENERATES MORE POWER THAN THEY CONSUME IN A MONTH?

A. Renewable resource energy generated by the customer in excess of their monthly consumption will be accumulated on a kWh basis, and credited to the customer's future monthly bills within the same calendar year.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW NET METERING WORKS.

A. For example, suppose a customer consumes 500 kWh that the Company provided on service days 1 through 15 of the month. The customer then self-provides to cover all of its usage and in addition, provides an excess of 500 kWh to the Company on days 16 through 30. The customer has benefited from the Company's distribution system not only during the first 15 days, but also during the second half of the month because the APS system was available to the customer for backup. However, the customer pays no transmission and distribution revenue for those costs priced in the energy portion of the bill and contributes nothing to the non-avoidable charges. The net consumption measured by the meter registers +500 – 500 kWh or zero for the month. Although this example is hypothetical, it proves the point that net metering leaves many costs uncollected. The same type of net flow could occur from hour to hour, rather than from day to day, as in this example.

Q. ARE YOU SAYING THAT THE RATE TREATMENT UNDER THIS SCHEDULE IS COST BASED?

A. No. Customers taking service under this schedule and producing any generation do not pay appropriate transmission and distribution costs, nor do they pay the full amount (and possibly not any) of non-avoidable charges such as the Competition Rules Compliance Charge, EPS Surcharge, Demand Side Management Cost Adjustment, Power Supply Adjustment (for deferred fuel costs incurred during prior periods) and Transmission Cost Adjustment. The customer's standard retail rate is designed to measure and price the distribution component of the rate when all consumption is supplied by the Company. For these reasons, the rate will not yield appropriate revenue to cover cost.

Q. WHY IS THE COMPANY PROPOSING A RATE SCHEDULE THAT WILL NOT RECOVER COSTS?

A. The Company is requesting this pilot rate schedule to promote customer owned renewable resource energy through the EPS. Because there will be the potential subsidies occurring between customers within a class, the Company will need to evaluate customer participation and impacts on revenue. At this point, the Company does not know what participation levels will be. Participation levels may depend on many factors, both demographic and rate schedule terms specific. At the end of the three year term of this pilot project, the Company will determine whether the terms of the schedule will need to be modified or even withdrawn.

Q. WHAT HAS THE COMPANY PROPOSED IN THIS RATE SCHEDULE TO MODERATE THE POTENTIAL UNWANTED IMPACT OF SUBSIDIES BETWEEN CUSTOMERS?

A. By setting a participation limit of 15 MW and limiting it to customer owned renewable resource generation facilities with a nameplate rating of 10 kW or less, the Company has targeted customers who have renewable energy facilities for the primary purposes of meeting their own energy needs, but occasionally have excess to provide to the Company. In addition, although this schedule permits excess energy to be carried from month to subsequent months, the customer's excess supply provided to the Company will be reset to zero at the end of each calendar year.

Q. WHY DOES APS PROPOSE THIS SCHEDULE AT THIS TIME?

A. The Company is establishing this pilot program to monitor the impacts of such an offering. The Commission, through distributed generation workshops, is studying interconnection rules and guidelines. The Company may make changes to this proposed rate schedule when final distributed generation rules are promulgated.

VI. SCHEDULE 1 – GENERAL TERMS AND CONDITIONS

Q. WHY ARE YOU PROPOSING REVISIONS TO SERVICE SCHEDULE 1?

A. APS is continually evaluating all aspects of its service schedules to enhance the Company's business practices. As part of this review, APS proposed certain revisions. These changes that are being proposed address situations where it may not be appropriate to bill a Service Establishment Charge, and add clarifying language that better reflects our envisioned business practices. A redline copy of the schedule is attached as Attachment GAD-6.

Q. PLEASE DESCRIBE THE SIGNIFICANT CHANGES TO SCHEDULE 1.

A. Section 2.2.4: APS is proposing clarifying language to Section 2.2.4. The special services discussed in this section are being performed outside of normal work hours, and usually require a crew with more than one person. The language clarifies that the $75.00 charge is per crew person, per hour.

Section 2.2.5: APS is proposing that the Company have the right to waive the Service Establishment Charge in instances where either 1) a name change is requested, but no field trip is necessary, or 2) where the Company has an active Landlord Agreement in place. The request for a name change typically may result when a surviving spouse requests that the service be placed in their name after the death of the customer of record, or a name has changed as a result of a divorce.

Landlord Agreements are legal contracts between the customer (the landlord) and APS that provide for continuous service to the landlord during the period the landlord does not have tenants. Where APS has an active Landlord Agreement, when the tenant, who has service in his or her name, notifies APS to

disconnect service, the service remains active and is automatically transferred back into the landlord's name until a request to transfer service into a new applicant's name is received. At that time APS obtains a meter read, and the new applicant is charged the Service Establishment Charge.

The Company is also proposing to reduce the Service Establishment Charge in those instances where multiple connect requests are made for the same location, such as a trailer park that has seasonal visitors. It is not unusual in those cases for the Company to receive a request to connect hundreds of meters on a specific day in the name of the trailer park. In that case, APS is proposing to charge only one Service Establishment Charge for every two requests for service connects made during the same site visit and placed in the same name, at the same address, for the same class of service.

Sections 4.3.3 & 4.3.4: APS is proposing to eliminate these sections that permit the Company to offer incentives for customers who elect to pay electronically and customers who elect to not receive a paper copy of their bill. Since the time the language was incorporated within Schedule 1, APS has not needed to offer any incentives. The number of customers choosing to pay electronically rather than receive a paper bill has increased steadily over the years without any incentive from APS. Regarding the automatic payment incentive, APS indicated in the report, almost 15% of our customers voluntarily participate in APS' automatic payment programs. According to recently published research findings from the *Chartwell's Guide to Bill Presentment and Payment 2005* report, the average participation rate for the utilities surveyed is 8.1%. Given APS' current robust participation rate, offering an incentive to entice customers to enroll is not needed, and as noted in Mr. Rumolo's testimony, would not be cost effective

even if it did increase participation. Similar to the automatic payment program, APS finds its customers who do utilize automatic payment programs are also choosing, without any incentives, to eliminate their paper bills.

Section 6.6: In Section 6.6, APS proposes language regarding master metering to clarify situations where prohibiting master metering is not applicable, such as a high rise residential unit where units are privately owned and the building is served by centralized heating (6.6.3), or senior care centers that provide packaged services such as housing, meals and nursing care (6.6.2).

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 significant impact to customers or to the Company. All the changes to Schedule 1 are redlined and set forth in Attachment GAD-6.

VII. SCHEDULE 4 – TOTALIZING

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 4.

A. The proposed change to Schedule 4 is being made to identify emerging metering technology. Schedule 4 addresses the Company's practice relative to totalizing of meter readings. It is applied when customers at a single premise receive service through multiple service points. APS is proposing language to address the emergence of new metering technology that allows for electronically totalized demand and energy, in addition to physical wire interconnections. A redlined copy of the proposed changes is attached as GAD-7.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A
Statement of Qualifications
Gregory A. DeLizio

Gregory A. DeLizio is Arizona Public Service Company's Supervisor of Regulations and Pricing. He has over 24 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 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 EIC
ENVIRONMENTAL IMPROVEMENT CHARGE

APPLICATION

The Environmental Improvement Charge ("EIC") shall apply to all retail Standard Offer service, excluding customers 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 EIC.

The EIC was approved by the Arizona Corporation Commission ("ACC") in Decision No. XXXXX. Cost recovery under the EIC shall be in accordance with the method described in the filed Environmental Improvement Charge Plan of Administration.

The EIC 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, or prospective environmental improvement projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC) and toxins such as mercury (Hg).

RATE

The charge shall be calculated at the following rate:

EIC

All kWh	$0.000152 per kWh

EIC PLAN OF ADMINISTRATION

The Environmental Improvement Charge ("EIC") Schedule recovers the cost associated with investment and expenses for environmental improvements at APS' generation facilities that the Arizona Corporation Commission ("ACC") has approved for recovery. The purpose of this Schedule is to allow for timely recovery of costs as environmental investments are made.

DETERMINATION OF EIC

The EIC will be determined in accordance with the following:

- On January 31, 2006, APS submitted its APS EIC Plan, which is a five year forecast of projected costs for environmental improvement projects. In addition, APS filed its proposed initial EIC calculated on an energy basis ($/kWh).

- The ACC approved those projects for inclusion within the EIC in Decision No., _____, issued on _____.

- The EIC 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. The EIC will exclude any component that was included in the test year upon which revenue requirement is collected in approved rates.

- The EIC 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, or prospective environmental improvement projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC) and toxins such as mercury (Hg).

- The initial EIC for bills rendered January 1, 2007 through June 30, 2008 (Billing Period 2007/2008) is computed based on actual data for calendar year 2004, plus actual and forecast data for calendar year 2005 and forecast data for calendar years 2006 and 2007, and reflects the amount of expenditures. The initial EIC calculation will use the Billing Period 2007/2008 forecast sales.

- The EIC for bills rendered July 1, 2008 through June 30, 2009 (Billing Period 2008/2009) will be calculated based on a true-up of the actual revenue collected under the EIC for the Billing Period 2007/2008 compared to the revenues that would have been collected had the Company had perfect knowledge on calendar years 2005, 2006 and 2007 actual amount of expenditures and actual Billing Period 2007/2008 sales. Added to the 2008/2009 Billing Period EIC will be calendar year 2008 forecast amount of expenditures. The EIC will utilize Billing Period 2008/2009 forecast sales.

- The EIC for bills rendered July 1, 2009 through June 30, 2010 (Billing Period 2009/2010) will be calculated based on a true-up of the actual revenue collected under the EIC for the Billing Period 2008/2009 compared to the revenues that would have been collected had the Company had perfect knowledge on calendar year 2008 actual amount of expenditures and Billing Period 2008/2009 actual sales. Added to the Billing Period 2009/2010 EIC will be calendar year 2009 forecast amount of expenditures. The EIC will utilize Billing Period 2009/2010 forecast sales.

- Subsequent EIC for bills rendered in subsequent billing periods will be calculated in the similar way as for Billing Period 2009/2010.

- APS will submit to the Commission any modifications to its APS EIC Plan and its proposed EIC for the upcoming July-June period with supporting data by March 15 preceding the Billing Period in which the EIC will be in effect. The ACC will review and approve, and/or modify and approve the proposed EIC by June 15 prior to the Billing Period. Should a ruling by the ACC not be rendered by the June 15 date, then APS will place the applicable EIC in effect as though approved subject to true-up in a subsequent filing. The EIC will apply to bills rendered on or after July 1 of the Billing Period and will be in effect until adjusted in a subsequent filing.

- 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, APS' forecasted sales and the revenue resulting from such application of the EIC.

- Any over or under collection made as part of the true-up process under the EIC will include interest.

- At the time rates into a subsequent rate case are approved, the EIC will be adjusted to reflect plant and expenses that are incorporated into rate base for the test year.

SCHEDULE GPS-1
CLASSIFIED SERVICE
GREEN POWER BLOCK SCHEDULE

APPLICATION

The Green Power Block Schedule shall be applied to Standard Offer customers with a pre-established service who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using a renewable resource including, but not limited to, solar, biomass, biogas, wind, geothermal, or small hydroelectric.
2. Generation not owned by the Company, but owned by another party for which the Company has contracted including, but not limited to, solar, biomass, wind, geothermal, or small hydroelectric.

In any event, the renewable energy that is provided under this rate schedule is limited to those resources eligible pursuant to A.A.C. R14-2-1618, as may be modified or updated from time to time.

TYPE OF SERVICE

The Company will offer electricity generated from renewable resources through the Company's electric distribution system.

The customer shall subscribe for a specific number of blocks of electricity generated from renewable resources. Each block shall equal 25 kWh/month. The monthly charge is based upon the number of blocks subscribed for by the customer. The Company may assign limits to the number of kWh blocks sold per customer.

The Company may assign limits to the subscription under this Schedule should reasonably priced renewable resources not be available.

For customers subscribing to more than 1000 blocks per month of electricity generated from renewable resources, the customer is required to contract for a minimum two year period.

SERVICE CHARGES

The bill for service under this rate schedule shall be $0.75 per month for each 25 kWh block of electricity generated from renewable resources.

SCHEDULE GPS-2
CLASSIFIED SERVICE
GREEN POWER PERCENT SCHEDULE

APPLICATION

The Green Power Percent Schedule shall be applied to standard offer customers on a pre-established service who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using a renewable source including, but not limited to, solar, biomass, biogas, wind, geothermal, or small hydroelectric.
2. Generation not owned by the Company, but owned by another party for which the Company has contracted including, but not limited to, solar, biomass, wind, geothermal, or small hydroelectric.

In any event, the renewable energy that is provided under this rate schedule is limited to those resources eligible pursuant to A.A.C. R14-2-1618, as may be modified or updated from time to time.

TYPE OF SERVICE

The Company will offer Green Power through the Company's electric distribution system.

The Company may assign limits to the subscription under this Schedule if reasonably priced renewable sources are not available.

For customers subscribing to more than 300,000 kWh-year of electricity generated from renewable resources, the customer is required to contract for a minimum two year period.

SERVICE CHARGES

Four options are available. The charges hereunder represent charges to be added to energy charges ($/kWh basis) under the customer's applicable schedule.

A. Green Power shall account for 100.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.03

B. Green Power shall account for 50.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.015

C. Green Power shall account for 30.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.009

D. Green Power shall account for 10.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.003

RATE SCHEDULE EPR-5
CLASSIFIED SERVICE
RATES FOR RENEWABLE RESOURCE FACILITIES OF 10 kW OR LESS FOR PARTIAL REQUIREMENTS

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 offered as a three-year pilot program to renewable resource generation facilities with a nameplate service continuous output power rating of 10 kW or less where the customer's generator(s) and load are located at the same premise. Renewable resources eligible to participate in this pilot program include solar and other renewable resources, as defined in A.A.C. R14-2-1618, as it may be modified or updated from time to time. This pilot program is capped at 15 MW of total renewable generation nameplate capacity. Environmental Portfolio Surcharge (EPS) funding will be utilized to recover the metering costs, billing system modification cost and revenue loss associated with the pilot program. This pilot program is conditioned upon continued and sufficient EPS funding. Participation under this schedule is subject to availability of enhanced metering and billing system upgrades.

TYPE OF SERVICE

Electric sales to the Company must be single phase or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises).

SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the customer in order to meet the customer's supplemental or interruptible electric requirements will be priced at the Standard Retail Rate as may be selected by the customer. Refer to the Definitions section, No. 5, of this rate schedule to identify rate schedules that qualify for this pilot program.

RATE

Energy will not be purchased from the customer under this schedule; instead, the kWh of energy provided will be credited to the customer. Through the net metering method, the customer shall receive the full retail value of the energy component (charges assessed on a kWh basis) of their bundled Standard Offer Service Rate for the power fed into the system from the customer-owned renewable resource generator(s). In cases where customer owned generation output exceeds the customer's total usage in a given month, the customer will receive a kWh credit equal to this excess generation output on the next monthly bill. Any remaining kWh credit amount will be zeroed out (no payment made to the customer) in the customer's last monthly bill rendered in the calendar year or at the time of a customer shut off. The Company shall provide one bi-directional meter under this EPR-5 pilot program.

CONTRACT PERIOD

Any applicable contract period(s) will be set forth in an Agreement between the customer and the Company.

DEFINITIONS

1. Partial Requirements Service – Electric service provided to a customer that has an interconnected renewable resource generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

DEFINITIONS (cont)

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

3. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

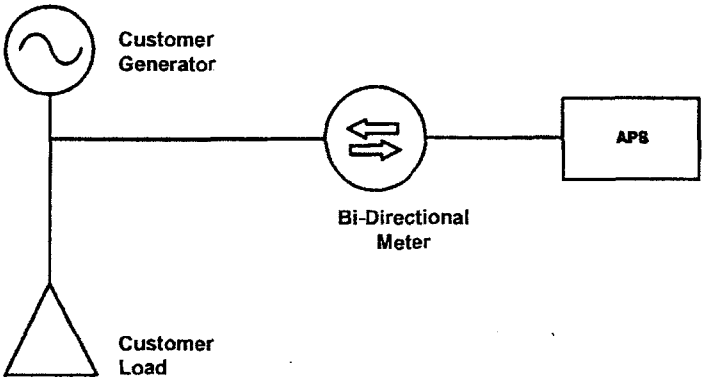
4. Pilot Program – The term of this pilot program is three years from the issuance of Decision No. XXXXX. If this experimental pilot rate schedule later becomes a standard Company rate schedule, the Company reserves the right to modify the rate schedule.

5. Standard Retail Rate – Qualifying standard retail rates for service under this pilot program are limited to Rate Schedules E-12, ET-1, ET-2, ECT-1R and ECT-2 for residential customers and Rate Schedules E-32 and E-32 TOU for general service customers with Monthly Maximum Demands of 20 kW or less.

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 Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities. This schedule has 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 interconnection or service agreement.

METERING CONFIGURATION



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 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.

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 day the request is being made, and Company

agrees to work the request on the same 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, 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.

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.

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 Establishment of Credit - Company shall not require a security deposit from a new applicant for service 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.

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.

2.5.2 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 Nonresidential 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 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 Nonresidential - Company may require a nonresidential 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.

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 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 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 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.

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.

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 nineteen (19) 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.

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 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.

4.3.2.1 Refunds 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 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.

4.4 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.

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 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 - 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, 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 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 is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter and the cost incurred to install the specialized meter. 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.

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 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.

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.

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;
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 Schedule 8, Bill Estimation, as filed with 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 will be billed for the estimated energy and, if applicable, demand, that would have registered had all energy and demand usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer 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, Condominiums - 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 – Company will allow master metering for high rise 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.

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 The existence of an obvious 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.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

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.

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.

~~1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.~~

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.

~~2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.~~

2.2 Service Establishment 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. ~~Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.~~

~~The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.~~

2.2.1 The customer ~~may~~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 ~~meter panel~~the point of delivery.

2.2.2 The customer ~~may~~will additionally be required to pay an after-hours charge of $75.00 ~~should~~if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established ~~during a period other than regular working hours, or on the same day of their request,~~after 5:00 p.m. on a day other than the day of request.

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 day the request is being made, and Company agrees to work the request on the same 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, 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.

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.

~~2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be $75.00 per hour.~~

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.

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 Establishment of Credit - Company shall not require a security deposit from a new applicant for service 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.

2.5.2 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 Nonresidential Establishment of Security Deposit ~~All nonresidential customers may~~ All non-residential applicants will be required to~~:2.5.3.1 Place~~ place a cash deposit to secure payment of bills for service as prescribed herein, ~~or~~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 ~~Provide~~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 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 Nonresidential - Company may require a nonresidential 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.

2.7.2 ~~2.7.1~~ Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by ~~the~~ Company in accordance with this section:

~~2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,~~

2.7.2.1 ~~2.7.1.2~~ 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 ~~2.7.1.3~~ 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 ~~APS~~Company is providing bundled electric service.

~~2.7.2 Separate security deposits may be required for each service location.~~

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 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 two (2) times the customer's average monthly bill as estimated by Company for the services being provided by ~~the~~ Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited 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.

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 ~~being served on a Standard Offer rate~~receiving bundled service, Company will use reasonable care in initially establishing service to the customer under the most advantageous ~~Standard Offer~~ 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 ~~Standard Offer~~ Optional Rates – Certain optional ~~Standard Offer~~ 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. ~~A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company.~~ Billing under the alternate rate will become effective from the next regularly scheduled meter reading, ~~or when~~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 ~~rate selection~~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.

3.5 Any customer ~~making a~~that selects Direct Access ~~rate selection~~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~~nineteen (~~15~~19) calendar days from the billing date. Any payment not received within this time frame ~~shall~~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 ~~services~~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.

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 ~~the~~ 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 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. ~~Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company 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. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.~~

4.3.2.1 Refunds 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.

~~4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to $10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.~~

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 last Company obtained meter read date.

~~4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.~~

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.

4.4 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 ~~shall~~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 ~~4.5 Field Call Charge~~ –Company ~~may~~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 ~~of~~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.

~~4.5.1~~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 ~~4.5.2~~ To avoid termination of service, the customer ~~may~~will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company ~~may~~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 ~~if~~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 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 - 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, 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 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 ~~existing~~ 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 is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter and the cost incurred to install the specialized meter. 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.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of ~~the~~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 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 ~~assure~~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. ~~The 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. In situations where Company suspects that a customer's load has a non-conforming 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 power factor of less than 90%, or leading, or other detrimental conditions shall be required to remedy problems in order to achieve a power factor in conformance with above standards, 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, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs~~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.

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.

~~6.1.2 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.~~

6.1.2 ~~6.1.3~~ 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 ~~be charged~~result in charge to the MSP of the replacement costs ~~less five (5) years depreciation~~, 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;
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. ~~In the event~~If Company must temporarily replace the MSP's meter and/or associated metering equipment ~~as necessary~~ 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 ~~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. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.~~ 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. ~~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 credentials~~

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.~~10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's Schedule 8, Bill Estimation, as filed with 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 will be billed for the estimated energy ~~consumption~~and, if applicable, demand, that would have registered had all energy and demand usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer ~~may~~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 ~~6.4.4 Customer will be billed~~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 ~~shall~~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, Condominiums~~ and Other Multiunit Residential Buildings~~ - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered~~ unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.~~. 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 – Company will allow master metering for high rise 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.

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 The existence of an obvious 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.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

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.

Attachment GAD- 7

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 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.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

1. The customer's <u>total</u> 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.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.

Attachment GAD- 7

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.

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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

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4. For Standard Offer customers, totalized metering may be accomplished by providing electronically totalized demand and energy reads or by means of ~~must be accomplished by~~ 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.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

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.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.

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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.

EXHIBIT
APS-38
admitted

REBUTTAL TESTIMONY OF GREGORY A. DeLIZIO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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REBUTTAL TESTIMONY OF GREGORY A. DeLIZIO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gregory A. DeLizio. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. SUMMARY

Q. WOULD YOU SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony addresses a number of issues and recommendations raised by Staff of the Arizona Corporation Commission ("Staff") and other parties in their direct testimony concerning the Company's proposals for an Environmental Improvement Charge ("EIC"), green power (electricity from renewable resources) rates, rates for partial requirements service, and rates for renewable resources. In addition, I address issues concerning the Company's Service Schedule 1.

III. SCHEDULE EIC - ENVIRONMENTAL IMPROVEMENT CHARGE

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE ENVIRONMENTAL IMPROVEMENT CHARGE (EIC) AS PROPOSED IN YOUR DIRECT TESTIMONY?

A. Yes. As indicated in Mr. Fox's rebuttal testimony, the Company has updated some of the costs of the environmental projects that were included in the EIC which was proposed in my direct testimony. In addition, APS has added six new

projects to the EIC plan, which are described in the Rebuttal Testimony of Mr. Ed Fox.

Q. HAS THE COMPANY CHANGED THE METHOD OF CALCULATING THE EIC COSTS AS PROPOSED IN YOUR DIRECT TESTIMONY?

A. No. The method of calculation and the underlying assumptions supporting the results have not changed from what was proposed in my Direct Testimony.

Q. WHAT IS THE CUSTOMER IMPACT OF THE PROPOSED CHANGES IN THE EIC CHARGE?

A. The updated initial EIC charge would be $0.00016 per kWh, which would be in place through June 2008. This charge would result in an average revenue increase of 0.19% and would increase the bill of an average residential customer consuming 1163 kWh per month by $0.19 per month. The EIC charge is projected to change over time, subject to subsequent Commission approval, as more environmental projects are undertaken. The updated Rate Schedule EIC is provided as Attachment GAD-1RB.

Q. IS THE COMPANY PROPOSING TO MAKE ANY CHANGES TO THE IMPLEMENTATION OF THE EIC?

A. No. The implementation of the EIC will be the same as what the Company originally proposed in my Direct Testimony, as detailed in the Plan of Administration attached to such testimony.

Q. HAVE YOU REVIEWED THE TESTIMONY OF STAFF AND OTHER PARTIES CONCERNING THE EIC?

A. Yes.

Q. PLEASE SUMMARIZE THEIR TESTIMONY.

A. Staff and the Residential Utility Consumer Office ("RUCO") oppose the EIC and

believe that environmental improvement costs should be recovered under the "traditional" rate making philosophy of waiting until the improvements are in service before determining whether the Company is entitled to recover for them. Their chief objection appears to be that the EIC is new and unique, that it doesn't fit what they believe are "traditional" rate making standards, and that it allows for cost changes outside of a general rate case. In addition, Staff opposes the EIC because, in their opinion, it would create a complicated audit process. RUCO also opposes the EIC because they believe that it violates the constitutional requirement for fair value rate making. Finally, AECC witness Kevin Higgins opposes the EIC without offering any empirical support for his opposition, other than the implementation of the EIC amounts to single issue rate making.

In contrast, Dave Berry, on behalf of Western Resource Advocates ("WRA"), supports the EIC to recover environmental improvement costs, including costs associated with green house gas abatement. Mr. Berry emphasizes that the EIC is needed because it highlights the environmental impacts of resource choices, encourages utilities to take actions that reduce environmental damages, and reduces the risk of complying with environmental regulations.

Q. WHAT IS YOUR RESPONSE TO STAFF'S POSITION ON THE EIC?

A. As addressed by Mr. Fox in his Rebuttal Testimony, it is impractical and counter productive to require that the Company first quantify the environmental benefits of emission control equipment before a project can be funded. Furthermore, Staff's contention that the denial of timely recovery of these types of costs would not impose a significant financial burden on the Company and that the Company should make the investment first and then seek recovery through traditional rate making or debt financing has missed one of the key points, if not the key point in

this entire proceeding, which is discussed in the Rebuttal Testimony of Mr. Wheeler. Capital is at a premium for APS and without the EIC, environmental projects are just another capital need in a very long line of competing needs. In addition, Mr. Fox in his Rebuttal Testimony, provides further detail on the expected environmental benefits of the EIC and why such a mechanism is necessary for the recovery of expected environmental costs instead of through a traditional rate case or bond financing or otherwise.

Q. IS THE COMPANY ASKING FOR PREAPPROVAL OF THE ENVIRONMENTAL PROJECTS AND/OR THEIR COSTS?

A. No. The Company is only seeking a more timely recovery of the environmental project costs. The Arizona Corporation Commission ("Commission" or "ACC") would still have an opportunity to review the projects and their costs for prudence, either in a general rate case or other proceeding.

Q. PLEASE EXPLAIN.

A. The Commission would have an opportunity to determine the prudency of such projects during APS' annual EIC filing, which is outlined in my Direct Testimony. The Commission would also have the opportunity for a prudence review of the costs of environmental projects as part of a rate case, when the Company seeks rate base treatment of those assets.

Q. WHAT HAPPENS IF PROJECT COSTS CHANGE IN SUBSEQUENT YEARS?

A. The EIC would be updated to reflect the actual project costs, as well as changes in projected costs, and then subject to the Commission's approval during the annual EIC filing.

Q. PLEASE ADDRESS STAFF'S CONCERN ABOUT THE AUDITING

PROCESS FOR THE EIC.

A. As outlined in my Direct Testimony, the Company has proposed a process for identifying and documenting the specific project costs and related revenue requirements to be recovered through the EIC. While the information would contain detailed project costs, the Company does not believe that any audit process would be any more complicated than auditing any other new plant addition because the information would be carefully separated from other Company costs.

Q. DO YOU AGREE WITH RUCO THAT THE EIC WOULD VIOLATE FAIR VALUE RATE MAKING?

A. I'm not a lawyer, but the Commission has already adopted similar mechanisms, such as the DSM, EPS and PSA adjustor mechanisms, as well as the arsenic surcharges discussed by Mr. Fox in his Rebuttal Testimony, which recover costs outside of a rate case. In addition, when APS seeks rate base treatment in the context of a rate case, the Commission has the opportunity to review and approve the projects and their costs.

Q. AECC CLAIMS THAT THE EIC AMOUNTS TO SINGLE ISSUE RATE MAKING. DO YOU AGREE?

A. Yes. That's true of all adjustment mechanisms, but it is not a compelling reason to deny the EIC. As I noted above, the Commission has historically approved similar mechanisms for recovery of public benefit programs, such as DSM and renewable costs outside of a rate case.

IV. <u>ADJUSTMENT SCHEDULE EPS-1 ENVIRONMENTAL PORTFOLIO STANDARD</u>

Q. WHY IS THE COMPANY PROPOSING TO MODIFY SCHEDULE EPS-1?

A. Decision No. 68668 required APS to set aside $4.25 million for additional funding for the Environmental Portfolio Standard ("EPS") Uniform Credit Purchase Program.

Q. HOW DOES APS INTEND TO RECOVER THIS ADDITIONAL FUNDING REQUIREMENT?

A. In her Direct Testimony, Ms. Keene of Staff recommends that APS be allowed to recover the $4.25 million through the Company's Adjustment Schedule EPS-1.

Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION?

A. Yes. The revised Adjustment Schedule EPS-1, which recovers the additional $4.25 million funding requirement, is provided as Attachment GAD-2RB. The rates and surcharge limits are identical to those proposed by Ms. Keene in her Direct Testimony.

V. PROPOSED GREEN POWER SCHEDULES

Q. DID STAFF OR ANY OTHER PARTIES COMMENT ON THE COMPANY'S PROPOSED GREEN POWER RATES GPS-1 AND GPS-2?

A. Yes, as set forth in the Direct Testimony of Ms. Keene, Staff recommends approval of Schedules GPS-1 and GPS-2 as proposed in my Direct Testimony. WRA witness Mr. Berry supports the concept of green power rates but recommends several revisions to APS' proposed rates.

Q. DO YOU AGREE WITH MR. BERRY'S RECOMMENDATIONS?

A. As addressed in the Rebuttal Testimony of Ms. Lockwood, APS agrees with a number of recommendations made by WRA concerning the green power rates, which are reflected in the revised Green Power Rate Schedules GPS-1A and GPS-2A.

Q. HOW IS THE COMPANY MODIFYING THE PROPOSED GREEN POWER RATE SCHEDULES?

The Company has modified the premium charge and the block size for the Green Power Schedules, GPS-1A and GPS-2A, which are the Green Power Block Schedule and the Green Power Percent Schedule respectively. The premium has changed from $0.03/kWh, as proposed in my Direct Testimony, to $0.01 per kWh. The Company is also proposing to increase the block size from 25 kWh, as proposed in my Direct Testimony, to 100 kWh per month. As a result, the monthly premium for green power in Schedule GPS-1A, has been changed from $0.75 for a 25 kWh for block of green power, as proposed in my direct testimony, to $1.00 for a 100 kWh block. The Company has also made commensurate changes in the green power premiums for the various percentages of monthly consumption in Schedule GPS-2A. The revised rate schedules GPS-1A and GPS-2A are provided as Attachments GAD-3RB and GAD-4RB.

Q. HOW WAS THE PREMIUM FOR GREEN POWER CALCULATED?

A. As described by Ms. Lockwood in her Rebuttal Testimony, the green power costs are based on actual energy costs for renewable projects that are used to serve the green power rate schedules. The Company's avoided generation costs are then netted against the renewable energy costs to derive the premium for green power.

Q. HOW DOES YOUR PROPOSED CALCULATION METHOD COMPARE WITH THAT PROPOSED BY WRA?

A. WRA witness Mr. Berry proposes that the premium for green power be calculated by determining the total cost per kWh for green power and subtracting the avoided generation costs as measured by the base power supply cost, the PSA and the allowance for capacity credits associated with the green power. Our proposed method is similar to WRA's proposal, except that we base the avoided generation

costs on the Company's avoided costs, which were filed on June 30, 2006, instead of the fuel, PSA, and capacity credits as proposed by Mr. Berry. We believe that our method provides a more accurate and fair way of determining the credit for the fuel and any capacity costs that the Company avoids as a result of the green power resource.

In addition, Mr. Berry suggests that the PSA could alternatively be factored into the equation by exempting the kWh served by green power from the customer's PSA charge, instead of subtracting the PSA from the green power cost to derive the green power premium. Mr. Berry suggests that the former method would help to stabilize the green power premium over time because the premium would not automatically change when the PSA is modified. The Company believes that this suggested change is unnecessary and inconsistent with our proposal because, as discussed, we propose to base the green power premium on filed avoided costs rather than using explicit values for fuel, PSA, and capacity credits as proposed by Mr. Berry.

Q. WHAT HAPPENS IF THE INITIAL GREEN POWER RESOURCES BECOME FULLY SUBSCRIBED OR IF THE PRICE OF GREEN POWER CHANGES?

A. If the initial amount of green power is fully subscribed, APS will seek to procure additional green power to serve additional customers under the green power schedules. APS will compute a new green power premium associated with the additional green power costs and the most recently approved avoided cost filing. If the new premium is different than the current premium, the Company will file new green power rates with the Commission for approval to accommodate the increased demand for the program. These new green power rates will be in addition to the current green power rates, which will not be changed outside of a

rate case. The initial offering of green power will be served under the proposed green power rates GPS-1A and GPS-2A. Any additional offering of green power will be served under new green power rates. If the green power rates are fully subscribed, additional green power will not be available to customers until the new rates are approved by the Commission. The individual green power rates will subsequently be consolidated into one rate in the next general rate case.

Q. WRA RECOMMENDED THAT THE GREEN POWER KWH BE EXEMPT FROM THE EIC AND EPS CHARGES. DO YOU AGREE?

A. Yes. The Company agrees that the green power kWh purchased through Schedules GPS-1A and GPS-2A should be excluded from the EPS and EIC charges. A customer participating in a green power rate would continue to be subject to EPS and EIC charges for the portion of their consumption that is not served under the green power rate schedules. Customers would also be subject to all other provisions in their otherwise applicable rate schedule, including adjustments, as applied to their total monthly consumption, which includes the green power portion. For example, the customer's total monthly consumption would be applied to the Power Supply Adjustment, the Transmission Cost Adjustment, the Competition Rules Compliance Charge, the Demand Side Management Adjustment, and any applicable taxes and government impositions.

In other words, the customer would be billed for their total monthly consumption according to all the provisions in their otherwise applicable rate schedule. However, the EIC and EPS charges would be based on the customer's total consumption less the green kWh. The green power premium, which includes the green power cost netted with the appropriate avoided generation costs associated with the green power kWh would then be added to the customer's bill.

Q. IS THE COMPANY RECOMMENDING ANY OTHER CHANGES TO GREEN POWER RATES?

A. Yes. The Company is proposing a Solar Power Pilot Program for residential customers, Schedule Solar-3. This Pilot Program will provide an option to residential customers to have either 50% or 100% of their monthly energy needs served from solar power. The Company will construct new utility-owned solar plants to serve customers participating in the program. The total amount of solar generation sold will not exceed the solar resources available from these solar plants. The Pilot Program will be available for three years.

Q. WHY IS THE COMPANY PROPOSING SCHEDULE SOLAR-3?

A. As described by Ms. Lockwood in her Rebuttal Testimony, the Total Solar Pilot Program will provide customers the option to have their energy needs served from solar power resources, that may not otherwise be able to (or desire to) participate in the Company's Solar Partners Inventive Program (formerly named as the Credit Purchase Program) for the installation their own solar photovoltaic system.

Q. PLEASE EXPLAIN RATE SCHEDULE SOLAR-3.

A. Schedule Solar-3 will apply to customers participating in the Total Solar Pilot Program in addition to their otherwise applicable rate schedule. Customer will be charged a premium for the solar power and credited for avoided generation costs, which will be based on the Company's avoided costs filing. The initial solar power cost of $0.394 per kWh will be netted against an avoided cost credit of $0.059 per kWh, which results in a premium for solar power of $0.335 per kWh. The solar kWh will not be subject to the EPS or EIC charges. All other provisions and charges of the customer's otherwise applicable rate schedule will be applied to their total monthly consumption, including the portion generated by solar

power. For example, the customer's total monthly consumption would be applied to the Power Supply Adjustment, the Transmission Cost Adjustment, the Competition Rules Compliance, the Demand Side Management Adjustment, and any applicable taxes and government impositions. Schedule Solar-3 is provided as Attachment GAD-6RB.

Q. HOW WAS THE PREMIUM FOR SOLAR POWER DERIVED?

A. The premium is based on the projected 25 year levelized cost of a single axis solar generation plant divided by the projected annual energy output from the solar plant. The premium is being addressed by Ms. Lockwood in her Rebuttal Testimony.

Q. HOW WAS THE AVOIDED COST CREDIT CALCULATED?

A. The avoided cost credit included in the proposed Solar-3 rate schedule is based on APS' 2007 non-firm seasonal avoided costs, which were filed with the ACC on June 30, 2006, as applied to the generation profile of a single axis solar generation plant over various seasons and time-of-use periods.

VI. NET METERING RATE EPR-5

Q. PLEASE SUMMARIZE THE TESTIMONY OF STAFF AND OTHER PARTIES CONCERNING THE PARTIAL SERVICE REQUIRMENTS SCHEDULE EPR-5 (NET METERING).

A. Staff witness Barbara Keene generally supports the EPR-5 net metering rate, but recommends that the proposed cap on the size of a participating renewable generator be increased from 10 kW to 100 kW and that the rate be available to customers on all rate schedules. Ms. Keene also recommends that two separate meters be used instead of the recommended bi-directional meter. That being said, Ms. Keene appears to generally support the Company's proposal to recover

incremental implementation costs and net lost revenue from the net metering program from environmental portfolio standard funds.

Solar Advocates witness Ed Smeloff proposes that the cap on individual system size be increased to 2 MW, that the overall program cap be increased to some higher level commensurate with an expanded RES program, and that the rate be made available to larger commercial customers. Mr. Smeloff does not object to the concept of the recovery of net lost revenues from the net metering program, but he does oppose that those amounts be funded out of the RES funds instead of through rates. Mr. Smeloff also proposes certain net metering policy issues, which go beyond the EPR-5 rate itself.

Q. THE TERMS NET METERING AND NET BILLING ARE USED FREQUENTLY IN DISCUSSIONS INVOLVING RENEWABLE RESOURCES DISTRIBUTED GENERATION. PLEASE EXPLAIN THESE TERMS.

A. The Energy Policy Act of 2005 defines net metering as "...service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period...." Net Billing, as defined in the Proposed Rulemaking for the Renewable Energy Standard and Tariff Rules (Decision No. 68566), "...is a system of billing a customer who installs an eligible Renewable Energy Resource generator on the customer's premises for retail electricity purchased at retail rates while crediting the customer's bill for any customer-generated electricity sold to the Affected Utility at avoided cost." The customer is charged the appropriate retail rate under the applicable APS rate schedule for their energy usage (sales to the customer). The

utility purchases excess energy from the customer at the current buy-back rate in accordance with the provisions of the applicable APS partial requirements rate schedule (EPR-2 or EPR-4). A bi-directional meter containing two separate metering registers is used to record sales to the customer and purchases from the customer. The main difference between net billing and net metering is reflected in this buyback rate.

The buyback rate is based on APS' avoided generation cost, which reflects the Company's most recently filed avoided costs and are based on wholesale generation market rates for on-peak and off-peak generation by season. Purchases from the customer only occur when the customer's generation exceeds the customer load at any given instant.

APS currently utilizes the net billing methodology for customers taking service under rate schedules EPR-2 and EPR-4.

Q. PLEASE EXPLAIN WHY THE COMPANY BELIEVES THE PROPOSED CAP ON INDIVIDUAL GENERATOR SIZE FOR THE SCHEDULE EPR-5 PARTIAL SERVICE REQUIREMENTS (NET METERING) PILOT PROGRAM IS APPROPRIATE.

A. APS believes that the proposed 10 kW cap on the individual generator size is appropriate for net metering, even in light of an expanded RES program because the Company already offers net billing rate options for distributed generation systems up to 100 kW, which do not have any cap on aggregate participation.

For example, APS currently offers rate Schedule EPR-2, which is available to all Qualifying Facilities ("QF") cogeneration and small power production facilities up to 100 kW. EPR-2 is similar to the proposed EPR-5 net metering rate in a number of ways. For example, the EPR-2 customer operates a distributed generation system in parallel with the APS grid. The customer is allowed to

generate all or part of their own energy needs with the backing of APS' system without paying for any standby charges. The customer is also compensated for any excess generation that flows back to the APS grid. The key difference between EPR-2 and the proposed EPR-5 net metering rate is that under EPR-2, the customer's excess generation is compensated at an avoided cost rate, while EPR-5 allows the excess energy to be netted against energy purchased from APS in subsequent months. The EPR-2 rate also has an additional monthly service charge to pay for the increased service costs, which the Company is proposing to eliminate as discussed below, while EPR-5 does not have an additional monthly charge.

The Company also currently offers Rate EPR-4 for renewable distributed generation up to 10 kW. EPR-4 is similar to EPR-2, but does not have the additional monthly service charge. Again, this rate offers most of the benefits of the proposed EPR-5 net metering rate; the difference being the method for compensating the customer for excess generation.

In addition, the Company provides partial requirement rates for distributed generators larger than 100 kW, as discussed in detail below. The Company believes that it is appropriate to handle these larger generators in this manner, rather than through a net metering arrangement, because of the standby issue discussed above.

Q. WHAT ABOUT THE OVERALL PROGRAM CAP OF 15 MW FOR THE NET METERING PILOT PROGRAM?

A. The Company believes that the proposed 15 MW cap on total aggregate participation in the EPR-5 net metering pilot program is appropriate, even in light of a potential expanded renewable energy program. The EPR-5 rate is proposed

as a pilot program, and is therefore designed to be a limited offering to provide an incentive for small customers to participate in the Company's Solar Partners Incentive Program (credit purchase program). In addition, as summarized above, the Company already offers other net metering/net billing type rates that do not have any aggregate cap on participation.

Q. WHAT LEVELS OF CAPS DO OTHER JURISDICITONS PLACE ON THEIR NET METERING PROGRAMS?

Most other jurisdictions that offer net metering have relatively small caps on the individual size of participating generators as well as the overall aggregate level of program participation. Out of the 41 states referenced by the Interstate Renewable Energy Council that offer net metering, 33 have caps on generator size at or below 100 kW. The Company believes that its proposal of 10 kW for the EPR-5 rate is consistent with these other jurisdictions because, as discussed, the Company already offers net billing rates, which provide most of the benefits of net metering, for customers with generators up to 100 kW in size.

Furthermore, 23 of the 41 states have caps on the aggregate level of participation. 18 of the 23 states that limit aggregate program participation have caps that are at or below 0.2% of the utility's peak load. Many of these states also have renewable energy standard requirements. The Company's proposed cap of 15 MW on aggregate participation is roughly equal to 0.2% of our "own-load" system peak, which is consistent with many other jurisdictions.

Q. DO YOU AGREE WITH MR. SMELOFF'S RECOMMENDATIONS FOR PROGRAM CAPS?

No. Mr. Smeloff cites several states with relatively high caps for individual generator size and for total MW allowed on a net metering program. The

Company believes that Mr. Smeloff's examples are outliers and should not be adopted in Arizona. In fact, only two states allow participation in net metering of generators up to 2 MW, as Mr. Smeloff is proposing for Arizona. Furthermore, in each of the states that Mr. Smeloff cites as examples to be followed, other than Colorado, the utilities have divested generation as part of retail competition and are facing very different generation procurement situations compared to APS. Therefore, their net metering programs are not illustrative of the best practices for APS and its customers.

Q. DO YOU AGREE THAT SCHEDULE EPR-5 SHOULD BE AVAILABLE TO ALL CUSTOMERS?

No. The Company has proposed that the EPR-5 net metering rate be available to residential customers and general service customers with monthly demands less than or equal to 20 kW. The net metering program, as proposed within this rate schedule, is intended to attract small customers to install renewable generation by providing an additional incentive beyond the credit purchase under the Company's Solar Partners Incentive Program.

Q. BUT WON'T LARGER COMMERCIAL CUSTOMERS ALSO WANT TO INSTALL RENEWABLE GENERATION?

A. We believe so. However, as discussed above, the Company already has other rates for larger customers with renewable generation, some of which have similar benefits of the proposed EPR-5 net metering rate. Again, the Company believes that the proposed availability of the EPR-5 rate in concert with other partial requirement rates will offer customers of all sizes on all rates beneficial and appropriate options for accommodating renewable generation, as well as other types of distributed generation.

Q. DO DISTRIBUTED GENERATION CUSTOMERS TYPICALLY SUPPLY EXCESS ENERGY TO THE APS DISTRIBUTION GRID?

A. No. The primary purpose of installing distributed generation has been to replace a portion of the utility provided electric load with on-site generation from a renewable resource. APS has interconnected over 300 distributed generators and only a small percentage of these customers supply excess energy to APS. In most instances the customer's load is significantly higher than the amount of on-site generation and 100% of the output of the distributed generator is used by the customer. The ability to sell excess energy to APS does not have a profound impact on the customer's decision to install on-site distributed generation.

Q. MS. KEENE RECOMMENDS THAT THE NET METERING RATE USE TWO METERS, RATHER THAN A SINGLE BI-DIRECTIONAL METER. DO YOU AGREE?

A. No. While the EPR-5 net metering rate could technically be implemented with two standard meters, the Company believes that a single bi-directional meter is a better option. At this time, two standard meters have a lower initial cost for the meter compared with a bi-directional meter. However, the customer would require additional electrical infrastructure costs, such as an additional meter base, sockets, adaptors and other meter-service costs, which eliminate any meter cost savings advantage. Furthermore, the Company prefers the operational requirements of the bi-directional meter for this application, which includes meter inventory, meter sets and meter reading. In fact, the Company is already using a single bi-directional meter for the current distributed generation (partial service requirements) rates, EPR-2 and EPR-4, discussed above. So the Company's metering proposal for EPR-5 would be consistent with our existing operations.

Q. WHAT KIND OF METERING DO OTHER JURISDICTIONS USE FOR NET METERING RATES?

A. Referring again to the net metering programs cited above, the vast majority of other jurisdictions which offer net metering use a single bi-directional meter to implement the rate; many jurisdictions require it. In fact, the Company has not been able to identify a single state that requires using two meters to implement net metering. Therefore, the Company believes that its proposal for using a bi-directional meter is consistent with industry and regulatory practice throughout the country.

Q. DID STAFF AND OTHER PARTIES SUPPORT THE RECOVERY OF NET LOST REVENUES FOR THE NET METERING PILOT PROGRAM?

A. In the direct testimony of Ms. Keene, Staff supports the concept of net lost revenue recovery for net metering. Solar Advocates witness Mr. Smeloff does not oppose net lost revenue recovery, but testified that the recovery should not be funded out of the EPS budget.

Q. DO YOU AGREE WITH THEIR RECOMMENDATIONS?

A. As I discussed in my Direct Testimony, the Company believes that it is appropriate to recover net lost revenue from the Net Metering Pilot Program, which offers a special financial subsidy to customers in order to promote small renewable distributed generation systems. The potential loss of kWh sales and the related net-revenue loss from the net metering program occur for two reasons. First, the Company is providing an incentive through the net metering rate to encourage customers to install renewable distributed generation. This generation reduces kWh sales that the Company may otherwise have made absent the program. While the participating customer provides some of their own energy needs through their distributed generator, they are still connected to the grid and rely on APS to back up their distributed generator and provide their remaining

energy needs.

The proposed net metering rate does not include a standby charge to recover APS' costs to back up the customer's generator, which is typical in other partial requirement rates which the Company offers. As a result, the customer will not pay their full costs for transmission, distribution or other fixed costs, especially for rate schedules that recover these costs through energy-based charges.

The second source of potential net-revenue loss occurs because the excess power that the customer generates above their own needs, which flows back to the grid, is compensated at an amount that is above the Company's avoided cost. The customer receives a credit equal to the entire energy charges in their applicable rate schedule, which includes generation, transmission, distribution, system benefits, DSM, PSA, regulatory assessment, CRCC, EPS and other energy-based charges.

Q. HOW WOULD THE NET LOST REVENUES BE CALCULATED?

A. The Company would incur lost kWh sales equal to the customer's total kWh generation and incur the associated lost revenues consistent with the customer's otherwise applicable rate schedule. The customers' generation kWh output would be calculated by applying a capacity factor to each customer's actual installed kW of generation. The lost revenues would be derived by applying the average kWh charges in the customer's otherwise applicable rate schedule to the lost kWh. The basic service charge and any kW charges would not typically be included in this calculation because the associated revenues are not likely to be reduced with distributed generation, as billed with the net metering rate schedule. This lost revenue would be calculated for each billing month for each participating customer.

The lost revenue would be netted against the associated avoided generation costs that the Company would not incur as the result of the distributed generation. Both the generation energy and capacity cost savings from net metering will be based on the Company's PURPA avoided costs, which are used to purchase excess energy from qualifying small distributed generators in the EPR-2 rate schedule. The Company's most recently filed avoided costs are based on wholesale generation market rates for on-peak and off-peak generation by season. These values would be used to assess the potential generation cost savings for solar, wind, biomass and other renewable technologies that could participate in a net metering program. A sample calculation of net lost revenue from net metering, which is based on assumptions concerning program participation, types of renewable systems, and excess power rates, is provided as Attachment GAD-5RB.

Q. HOW WOULD THE NET LOST REVENUES BE ADMINISTERED?

A. The net lost revenues would be recovered through the EPS budget and reported to the Commission as part of the reporting requirements of the EPS program.

VII. RATES FOR PARTIAL SERVICE REQUIREMENTS

Q. PLEASE EXPLAIN THE CONCEPT OF PARTIAL REQUIREMENT RATES.

A. Partial requirement rates are applicable to customers who utilize distributed generation to self-provide a portion of their electric load. In order to provide reliable service to a partial requirements customer, APS must have adequate facilities in place to meet 100% of the customer's electric load requirements when the distributed generator is not in operation (e.g. generator outage, scheduled maintenance, etc.).

Q. WHAT ARE APS' CURRENT PARTIAL REQURIEMENT RATES?

A. APS offers the following partial requirements service rate schedules:

EPR-2: EPR-2 is applicable to qualified cogeneration and small power production facilities under 100 kW. This rate schedule offers monthly purchase rates for energy the customer does not use that is delivered to the Company. The customer is responsible for the additional costs associated with the installation of bi-directional metering in addition to monthly service charge based on the type of service (e.g. single- or three-phase) provided. All other provisions of the customer's otherwise applicable rates schedule will continue to apply.

EPR-3: EPR-3 is applicable to qualified solar/photovoltaic small power production facilities 10 kW and less and is similar to rate schedule EPR-2 with a few exceptions. Under EPR-3 there are no monthly service charges based on the type of service and the customer is not charged for the installation of bi-directional metering. EPR-3 also offers a simultaneous buy/sell metering arrangement where the customer can elect to have APS provide 100% of their electric requirements while selling 100% of the output of the generator to APS. This rate is frozen to new customers.

EPR-4: EPR-4 is applicable to qualified small power production facilities 10 kW or less utilizing renewable resource technologies and is similar to EPR-2 with two exceptions. Under EPR-4 there are no monthly service charges based on the type of service and the customer is not charged for the installation of bi-directional metering.

E-32-R: E-32-R is applicable to general service customers who are also served under Schedule E-32. All billing is in accordance with Schedule E-32 with one exception. The customer's billing kW is the greater of: 1) the average kW

supplied during the 15-minute period for maximum use during the month; 2) 80% of the average of the highest kW measured during each of the six (6) summer billing months; or 3) the minimum kW specified in the agreement for service or individual customer contract. The Company currently has three customers being served under Schedule E-32R.

E-51: E-51 is an optional electric service for qualified facilities over 100 kW. It contains a daily basic service and generation meter charges, supplemental service charges provided in accordance with the rate levels contained in rate schedule E-32 or E-34, Standby Service charges based on the amount of capacity reserved by the customer, and maintenance service charges applicable when the customer's generator is down for scheduled maintenance. This rate schedule is frozen to new customers. The Company currently has two customers being served under Schedule E-51.

E-52: E-52 is a partial requirements service available to customers with an aggregate partial requirements service load less than 3,000 kW. It contains per day basic service and generation meter charges, supplemental service charges provided in accordance with the rate levels contained in rate schedule E-32, Standby Service charges based on the amount of capacity reserved by the customer, and maintenance service charges applicable when the customer's generator is down for scheduled maintenance. The Company currently has no customers being served under Schedule E-52.

E-55: E-55 is a partial requirements service available to customers with an aggregate partial requirements service load of 3,000 kW and above. It contains per day basic service and generation meter charges, supplemental service charges provided in accordance with the rate levels contained in rate schedule E-34,

Standby Service charges based on the amount of capacity reserved by the customer, and maintenance service charges. The Company currently has one customer being served under Schedule E-55.

EQF-S: EQF-S is applicable to qualified cogeneration and small power production facilities 100 kW and less capable of producing firm power. This rate offers quantities of standby power to a customer who is not taking full requirements service from the Company and who desires a permanent electric connection as standby power source. The Company currently has no customers being served under Schedule EQF-S.

EQF-M: EQF-M is applicable to qualified cogeneration and small power production facilities 100 kW and less capable of producing firm power. This rate offers quantities of contracted maintenance capacity, taken during scheduled periods, to a customer who is not taking full requirements service from the Company and who desires a permanent electric connection as maintenance power source. The Company currently has no customers being served under Schedule EQF-M.

Q. WHAT WERE OTHER PARTIES COMMENTS ON APS' PARTIAL REQUIREMENT RATES?

A. Distributed Energy Association of Arizona ("DEAA") witness William Murphy took exception to APS' partial requirements rates and recommended the development of a new partial requirements rate schedule. Mr. Murphy also proposed criteria which, in his opinion, should be used to develop new partial requirements rates.

Q. DO YOU AGREE WITH MR. MURPHY'S COMMENTS?

A. For the most part, no. As discussed in the Rebuttal Testimony of APS witness

David Rumolo, Mr. Murphy's general rate design philosophy is fundamentally flawed and his proposed partial requirements rate design philosophy has no basis in cost causation. Furthermore, Mr. Murphy presents no evidence to support his claims that APS' demand and energy rate schedule components are not cost-based. Thus, the Company strongly disagrees with both of these assertions.

Mr. Murphy also claimed that the Company's partial requirements rates were complicated and not easy to understand. The Company agrees that Partial Requirement Rate Schedules E-52 and E-55 are somewhat complicated and is proposing several changes to the partial requirement rate schedules to address this issue. In addition, the Company proposes to combine several of its partial requirements rates in order to make it easier for a customer with distributed generation to select the best option.

Q. WHAT ARE THE CHANGES THAT THE COMPANY IS PROPOSING FOR ITS PARTIAL REQUREMENTS RATES?

A. In addition to the new EPR-5 rate schedule proposed in my Direct Testimony and discussed in more detail above, the Company is proposing modifications to the existing EPR-2 rate schedule and is proposing two additional partial requirements rate schedules (E-56 and E-57). APS is proposing to: (1) eliminate existing rate schedules EPR-3, EQF-S, EQF-M, and E-52, which are currently frozen and therefore not available to new customers; (2) close (freeze) existing rate schedules E-32R, and E-55 to new customers and eliminate them in the next rate case; (3) eliminate schedule E-51, which is currently frozen, in the Company's next rate case, and (4) consolidate Schedule EPR-4 into the revised Schedule EPR-2.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO RATE SCHEDULE EPR-2.

A. The Company has updated the buyback rate in schedules EPR-2 to incorporate the avoided costs, which were filed on June 30, 2006. In addition, the Company made minor wording changes to be able to use these schedules with the new residential time-of-use rates ET-2 and ECT-2; eliminated the monthly service charge which was dependant on the customer's type of service; changed the summer and winter billing cycle months to match APS' other rate schedules; eliminated the requirement for the Customer to share in the cost of bi-directional metering; and removed a provision that allowed the customer to pay the incremental metering costs over a five year period. The revised Schedule EPR-2 is provided as Attachment GAD-7RB.

Q. WHY IS SCHEDULE EPR-3 BEING ELIMINATED?

A. The Company believes that the proposed net metering rate EPR-5 and the rate EPR-2, with the proposed changes, are better options for customers compared with Schedule EPR-3. EPR-3 is frozen with no customers currently on the rate.

Q. WHY IS SCHEDULE EPR-4 BEING CONSOLIDATED WITH SCHEDULE EPR-2?

A. The Company's proposed revisions to Schedule EPR-2 make the provisions of service identical to the existing Schedule EPR-4. Therefore, Schedule EPR-4 is being consolidated into the revised EPR-2 rate. The Company is currently serving 249 customers under the EPR-4 rate.

Q. WHY ARE SCHEDULES E-52, EQF-S, AND EQF-M BEING ELIMINATED?

A. Schedules E-52, EQF-S, and EQF-M are being replaced by the revised Schedules EPR-2, E-56 and E-57. There are currently no customers being served under these rates.

Q. WHAT DOES THE COMPANY PROPOSE FOR RATE SCHEDULE E-51?

A. The Company proposes that rate schedule E-51, which is currently frozen, should be eliminated in the next general rate proceeding because it will be replaced by the proposed rate E-56. APS currently has two customers served under Schedule E-51.

Q. WHY ARE SCHEDULES E-32R AND E-55 BEING FROZEN TO NEW CUSTOMERS?

A. APS' proposed new Partial Requirements Rates Schedules E-56 and E-57 will replace schedules E-32R and E-55. The Company is currently serving three customers under E-32R and one customer under E-55.

Q. PLEASE DESCRIBE THE PROPOSED PARTIAL REQUIREMENTS RATE E-56.

A. Partial Service Rate Schedule E-56 is applicable to general service customers having distributed generating equipment 100 kW or greater capable of supplying all or a portion of its power requirements. The main components of the rate schedule include:

(1) A Basic Service component which is comprised of the unbundled monthly Basic Service and Revenue Cycle Service charges included in the customer's applicable General Service rate schedule;

(2) Supplemental Service is defined as the demand and energy needs contracted by the customer to augment the power and energy generated by the customers' generation facility. Supplemental Service will be provided in accordance with the monthly rate levels contained in the customer's applicable General Service rate schedule excluding the monthly Basic Service and Revenue Cycle Service Charges (these are already included in the above-mentioned Basic Service component); and,

(3) Standby and Maintenance Service, which is the sum of demand and energy charges, derived as follows:

Demand Charge: The Demand Charge is the unbundled transmission charge, if applicable, contained in the Customer's General Service rate schedule plus the unbundled delivery charge contained in the Customer's General Service rate schedule. This summation is then multiplied by the amount of Contract Standby Capacity. Contract Standby Capacity is defined as the greater of; a) the measured kW output of each customer self-generation unit at the time of start-up testing; or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed the Customer's actual load.

Energy Charge: Defined as the electric energy supplied by the Company to replace power normally supplied by the Customer's generator(s) during unscheduled full outages, unscheduled partial outages, and scheduled maintenance periods. The unbundled transmission charge, if applicable, contained in the Customer's General Service rate schedule plus the per kWh monthly firm power purchase rates shown in rate schedule EPR-2.

The Company will install, at the customer's expense, a generator meter(s) at the point(s) of output from each of the customer's generators. This allows the Company to accurately meter customers taking service under this rate schedule. Rate Schedule E-56 is provided as Attachment GAD-8RB.

Q. PLEASE DESCRIBE THE PROPOSED SOLAR PARTIAL REQUIREMENT RATE E-57.

A. Rate schedule E-57 is applicable to general service customers having solar/photovoltaic generating equipment greater than 100 kW but less than 1,000 kW capable of supplying all or a portion of its power requirements. The main

components of the rate schedule include:

(1) A basic service component that is comprised of the unbundled monthly Basic Service and Revenue Cycle Service charges included in the customer's applicable General Service rates schedule;

(2) Supplemental Service is defined as the demand and energy needs contracted by the customer to augment the power and energy generated by the customers' generation facility. Supplemental Service, to include 100% of the customer's energy requirements, will be provided in accordance with the monthly rate levels contained in the customer's applicable General Service rate schedule excluding the monthly Basic Service and Revenue Cycle Service Charges (these are already included in the above-mentioned Basic Service component); and,

(3) A monthly Standby Service component is derived by multiplying the unbundled delivery charge contained in the Customer's applicable General Service rate schedule by the 15 minute integrated kW measured on the customer's generator meter(s) during the customer's monthly peak demand.

(4) The Company will pay the customer for any excess energy produced by the distributed generator at the purchase rates specified in the Schedule EPR-2 that are based on the Company's avoided cost.

The Company will install, at the customer's expense, a generator meter(s) at the point (s) of output from each of the customer's generators. This allows the Company to accurately meter customers taking service under this rate schedule. Rate Schedule E-57 is provided as Attachment GAD-9RB.

VIII. GENERAL TERMS AND CONDITIONS

Q. HAS THE COMPANY PROPOSED ANY ADDITIONAL CHANGES TO SCHEDULE 1?

A. Yes. In addition to the changes discussed in my Direct Testimony, we have proposed a few minor wording changes that clarify certain changes and their application. The revised Schedule 1 is provided as Attachment GAD-10RB.

Q. DOES THE COMPANY AGREE WITH STAFF'S RECOMMENDATION CONCERING THE $75 TRIP CHARGE?

A. No. As discussed in my Direct Testimony, Section 2.2.4 refers to charges for work performed outside of normal work hours, at the customer's option and request, which usually requires a crew with more than one person. The Company is proposing to clarify that the $75 charge is per crew person, per hour. Staff witness Ms. Andreasen recommends that the charge remain at $75 per hour, regardless of how many workers are required. The Company believes that Staff's recommendation will not appropriately recover the Company's costs and will shift those costs to other customers. In addition, Staff's proposal will not send the proper price signal to customers as to the true costs of requesting after hours work.

IX. E3 AND E4 LOW INCOME AND MEDICAL DISCOUNT PROGRAMS

Q. WHY IS THE COMPANY PROPOSING TO CHANGE THE E-3 AND E-4 MEDICAL DISCOUNT PROGRAM AT THIS TIME?

A. In Decision No. 68685 the Commission directed APS to propose ways to implement automatic enrollment of customers in the E-3 and E-4 low income and medical discount programs as part of this rate case. These changes are discussed in the Rebuttal Testimony of APS witness Terry Orlick. The proposed changes to the related rate schedules and plans of administration are necessary to ensure that all eligible customers can participate in the programs and to enable additional

enrollment mechanisms for the E-3 discount program.

Q. HOW DOES APS PROPOSE TO CHANGE SCHEDULES E-3 AND E-4 AND THE RELATED PLANS OF ADMINISTRATION?

A. The Company proposes to insert additional language in the Plans of Administration for Schedules E-3 and E-4 that would allow other community action agencies, in addition to the Arizona Department of Economic Security ("DES"), to apply the income eligibility guidelines specified in the rates. Currently only DES can determine if a customer is eligible for the rates. In addition, the Plan of Administration for Schedule E-3 required some minor language changes to ensure that residential customers on all rate schedules are eligible for the discount. Clarifying language has also been added to Schedules E-3 and E-4 to clarify that customers cannot participate in both the E-3 and E-4 discounts concurrently, which is consistent with current practice. The revised Schedules E-3 and E-4 are provided as Attachment GAD-11RB and Attachment GAD-12RB respectively. The revised Plans of Administration for E-3 and E-4 are provided as Attachment GAD-13RB and Attachment GAD-14RB respectively.

X. ADMINISTRATIVE ISSUES

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 Direct and Rebuttal Testimony. However, some of the optional rates which I have proposed in my Direct and Rebuttal Testimony will require additional time to implement after an order is received in this proceeding to accommodate required billing, metering and related systems .

XI. CONCLUSION

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. APS is requesting that the Commission authorize the following: the implementation of the EIC as proposed by the Company; modification of the Company's Schedule EPS-1 to recover an additional $4.25 million spent by the Company; adoption of two new Company proposed Green Power Schedules GPS-1A and GPS-2A; a new Company proposed Schedule Solar-3; partial requirements rates in EPR-5 for net metering and E-56 and EPR-57 for customer distributed generators in excess of 100kW; consolidation of EPR-4 and EPR-2; freezing of E-55, E51 and E32-R to new customers; and withdrawal of EQF-S and EQF-M. The Company also requests approval to modify its Service Schedule 1 and Service Schedule 4, as proposed.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

ENVIRONMENTAL IMPROVEMENT CHARGE

APPLICATION

The Environmental Improvement Charge ("EIC") shall apply to all retail Standard Offer service, excluding kWh served in accordance with solar rates SP-1 (Solar Partners), Solar-2, Solar-3, 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 EIC.

The EIC was approved by the Arizona Corporation Commission ("ACC") in Decision No. XXXXX. Cost recovery under the EIC shall be in accordance with the method described in the filed Environmental Improvement Charge Plan of Administration.

The EIC 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, or prospective environmental improvement projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC) and toxins such as mercury (Hg).

RATE

The charge shall be calculated at the following rate:

EIC

All kWh	$0.00016 per kWh

APPLICATION

The Environmental Portfolio Surcharge Adjustor shall apply to all retail Standard Offer or Direct Access service, excluding kWh served in accordance with solar rates SP-1 (Solar Partners), Solar-2, Solar-3, ~~SP-1~~, and Green Power Schedules GPS-1 and GPS-2. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. From time to time the EPS program spending requirements will be evaluated and if necessary the charge and/or caps will be altered if approved by the Commission. Any new charges/caps will be applied in billing cycle 1 beginning in the month following Commission approval and will not be prorated. Details regarding the administration of this surcharge can be found in the filed Environmental Portfolio Surcharge Plan for Administration. The EPS Surcharge and the Demand Side Management Adjustment Charge may be combined on the customer's bill and shown on the "Environmental Benefits Surcharge" line.

RATES

The bill shall be calculated at the following rates:

All kWh	~~$ 0.000875~~$0.001392	per kWh

SURCHARGE LIMITS

The monthly total of the Environmental Portfolio Surcharge shall not exceed the following limits:

Residential Customers	~~$ 0.35~~$0.56	per service per month
Non-residential Customers	~~$13.00~~$20.68	per service per month
Non-residential Customers with demand of 3,000 kW or higher per month for three consecutive months	~~$39.00~~$62.04	per service per month

APPLICATION

The Environmental Portfolio Surcharge Adjustor shall apply to all retail Standard Offer or Direct Access service, excluding kWh served in accordance with solar rates SP-1 (Solar Partners), Solar-2, Solar-3, and Green Power Schedules GPS-1 and GPS-2. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. From time to time the EPS program spending requirements will be evaluated and if necessary the charge and/or caps will be altered if approved by the Commission. Any new charges/caps will be applied in billing cycle 1 beginning in the month following Commission approval and will not be prorated. Details regarding the administration of this surcharge can be found in the filed Environmental Portfolio Surcharge Plan for Administration. The EPS Surcharge and the Demand Side Management Adjustment Charge may be combined on the customer's bill and shown on the "Environmental Benefits Surcharge" line.

RATES

The bill shall be calculated at the following rates:

All kWh	$0.001392	per kWh

SURCHARGE LIMITS

The monthly total of the Environmental Portfolio Surcharge shall not exceed the following limits:

Residential Customers	$0.56	per service per month
Non-residential Customers	$20.68	per service per month
Non-residential Customers with demand of 3,000 kW or higher per month for three consecutive months	$62.04	per service per month

APPLICATION

The Green Power Block Schedule shall be applied to Standard Offer customers who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. However, the charges in Schedule EIC and Adjustment Schedule EPS-1 will not apply to the kWh served in accordance with Schedule GPS-1A.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using a renewable resource including, but not limited to, solar, biomass, biogas, wind, geothermal, or small hydroelectric.
2. Generation not owned by the Company, but owned by another party for which the Company has contracted including, but not limited to, solar, biomass, wind, geothermal, or small hydroelectric.

In any event, the renewable energy that is provided under this rate schedule is limited to those resources eligible pursuant to A.A.C. R14-2-1618, as may be modified or updated from time to time.

TYPE OF SERVICE

The Company will offer electricity generated from renewable resources through the Company's electric distribution system.

The customer shall subscribe for a specific number of blocks of electricity generated from renewable resources. Each block shall equal 100 kWh per month. The monthly charge is based upon the number of blocks subscribed for by the customer. The Company may assign limits to the number of kWh blocks sold per customer.

Subscription to GPS-1 may be limited by the availability of renewable resources in APS' green power portfolio.

Customers are required to subscribe for a minimum of one year. Customers may cancel GPS-1 service if the charge increases during the one year commitment.

SERVICE CHARGES

The bill for service under this rate schedule shall be $1.00 per month for each 100 kWh block of electricity generated from renewable resources.

SCHEDULE GPS-2A
CLASSIFIED SERVICE
GREEN POWER PERCENT SCHEDULE

APPLICATION

The Green Power Percent Schedule shall be applied to Standard Offer customers who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. However, the charges in Schedules EIC and Adjustment Schedule EPS-1 will not apply to the kWh served in accordance with Schedule GPS-2A.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using a renewable source including, but not limited to, solar, biomass, biogas, wind, geothermal, or small hydroelectric.
2. Generation not owned by the Company, but owned by another party for which the Company has contracted including, but not limited to, solar, biomass, wind, geothermal, or small hydroelectric.

In any event, the renewable energy that is provided under this rate schedule is limited to those resources eligible pursuant to A.A.C. R14-2-1618, as may be modified or updated from time to time.

TYPE OF SERVICE

The Company will offer Green Power through the Company's electric distribution system.

Subscription to GPS-2 may be limited by the availability of renewable resources in APS' green power portfolio.

Customers are required to subscribe for a minimum of one year. Customers may cancel GPS-2 service if the charge increases during the one year commitment.

SERVICE CHARGES

Four options are available. The charges hereunder represent charges to be added to energy charges ($/kWh basis) under the customer's applicable schedule.

A. Green Power shall account for 100.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.01

B. Green Power shall account for 50.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.005

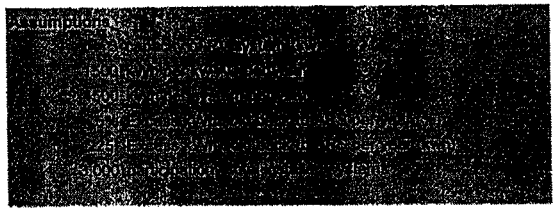
C. Green Power shall account for 35.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.0035

D. Green Power shall account for 10.0% of the generation mix in the customer's service.
Additional Charge per kWh: $0.001

ARIZONA PUBLIC SERVICE COMPANY

Potential Revenue Erosion and Net Lost Revenues from Net Metering Rate

Attachment GAD-5RB



Revenue erosion and net lost revenue from excess customer generation
For 3,000 photovotaic systems at 3 KW capacity each
Valued at average energy-related charges - proposed rate
(excludes basic service charge and demand charges)

	Installed Systems	Total Generation kWh	Rates Annual Average $/kWh	Lost Revenue	Avoided Cost Annual Average $/kwh	Avoided Cost $	Net Lost Revenue
E12	1,200	5,400,000	0.10895	$ 588,352	$ 0.05765	$ 311,303	$ 277,049
ET1	1,200	5,400,000	0.09913	$ 535,324	$ 0.05765	$ 311,303	$ 224,021
ECT1R	300	1,350,000	0.05007	$ 67,589	$ 0.05765	$ 77,826	$ (10,237)
E32 (0-20 kW)	300	1,350,000	0.11466	$ 154,791	$ 0.05765	$ 77,826	$ 76,965
	3,000	13,500,000		$ 1,346,055		$ 778,257	$ 567,798

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 construct new utility-owned solar plants to support customers taking service under this Rate Schedule. The total amount of solar generation sold shall not exceed the solar resources available from these solar plants.

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 Schedule EIC and Adjustment Schedule EPS-1 will not apply to the kWh served in accordance with Schedule Solar-3. 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:	$0.394 per kWh
Avoided Cost Credit:	$0.059 per kWh
Solar Power Premium Rate:	$0.335 per kWh

Solar Power Energy shall be a percentage of the customer's total monthly energy (kWh). Two options are available:

A. Solar Power shall account for 100.0% of the customer's monthly energy.

B. Solar Power shall account for 50.0% of the generation mix in the customer's service.

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.

SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES 100KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate schedule is available in all territory served by Company.

APPLICATION

This rate schedule is applicable to all cogeneration and small power production facilities with a nameplate continuous AC output power rating of 100 kW or less where the facility's generator(s) and load are located at the same premises and that otherwise meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to qualifying facilities (QF's) electing to configure their systems as to require partial requirements service from the Company in order to meet their electric requirements.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the QF will be responsible for all incremental costs incurred to accommodate such an arrangement.

PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the Customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the Customer for any energy purchased as calculated on the standard purchase rate (see below).

MONTHLY PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (May - October)	6.486	4.531	7.630	5.330
Winter Billing Cycles (November - April)	6.384	4.905	7.510	5.770

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's otherwise applicable retail rate schedule

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually.

CONTRACT PERIOD

As provided for in any Supply/Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service – Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

3. Non-Firm Power - Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided, and the power can be interrupted by the Customer at any time.

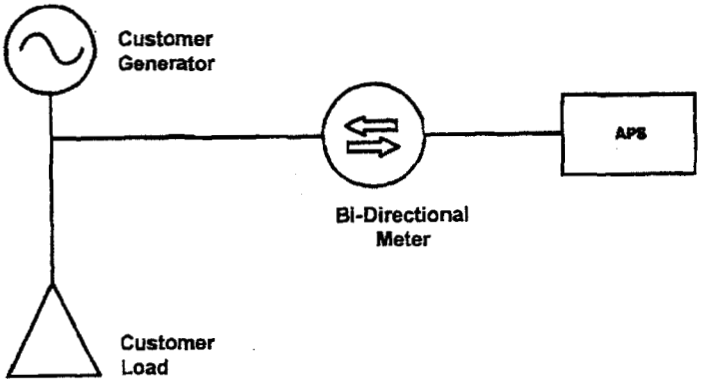
4. Firm Power - Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

5. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

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, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection Requirements for Distributed Generation. This schedule has 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 interconnection or Supply/Purchase agreement.

METERING CONFIGURATION



~~RATE~~ SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
~~UNDER~~ 100 ~~kW~~KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate schedule is available in all territory served by the Company.

APPLICATION

This rate schedule is applicable to all cogeneration and small power production facilities with a nameplate continuous AC output power rating of 100 kW or less where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying status pursuant to Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. ~~This schedule is a~~Applicable only to qualifying facilities (QF's) electing to configure their systems as to require ~~only~~ partial requirements ~~or interruptible~~ service from the Company in order to meet their electric requirements.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by the customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the QF will be responsible for all incremental costs incurred to accommodate such an arrangement.

PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the customer for any energy purchased as calculated on the standard purchase rate (see below).

MONTHLY PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (~~June~~ May - October)	~~3.551~~6.486	~~2.257~~4.531	~~5.433~~7.630	~~3.453~~5.330
Winter Billing Cycles (November - ~~May~~April)	~~2.552~~6.384	~~1.871~~4.905	~~3.904~~7.510	~~2.862~~5.770

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's otherwise applicable retail rate schedule

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually. ~~to reflect changes in the Company's fuel costs.~~

~~SERVICE CHARGE~~

~~The monthly service charge shall be determined in accordance with the type of customer service characteristics as set forth below:~~

	~~Monthly Charge~~
~~Single Phase Service:~~	
~~0-200 amp service~~	~~$ 7.34~~
~~Three Phase Service:~~	
~~0-200 amp service~~	~~$ 8.87~~
~~201-400 amp service~~	~~$ 18.31~~

CONTRACT PERIOD

~~Any applicable contract period will be set forth in the customer's~~As provided for in any Supply/Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service - ~~A QF's system configuration whereby the output from its electric generator(s) first go to supply its own electric requirements with any excess energy (over and above its own requirements at the time) then being sold to the Company.~~Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their ~~QF's~~ own generation facilities). This configuration~~also~~ may also be referred to as the "parallel mode" of operation.

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

   - ~~Interruptible Power - Electric energy or capacity supplied by the Company subject to interruption by the Company under specified conditions and under agreed upon lead time requirements.~~

3. Non-Firm Power - Electric power which is supplied by the ~~power producer~~Customer's generator at the Customer's~~producer's~~ option, where no firm guarantee is provided, and the power can be interrupted by the Customer~~power producer~~ at any time.

4. Firm Power - Power available, upon demand, at all times (except for forced outages~~ and scheduled maintenance~~) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

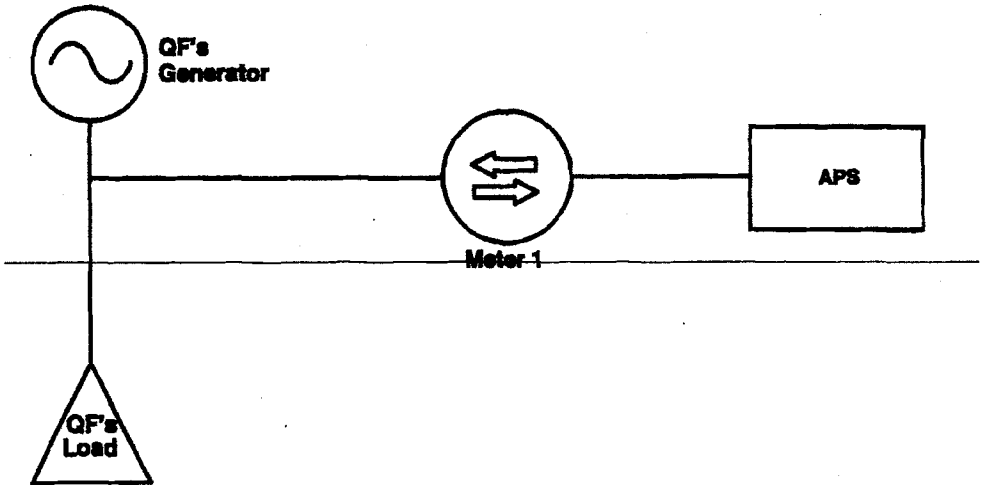
5. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

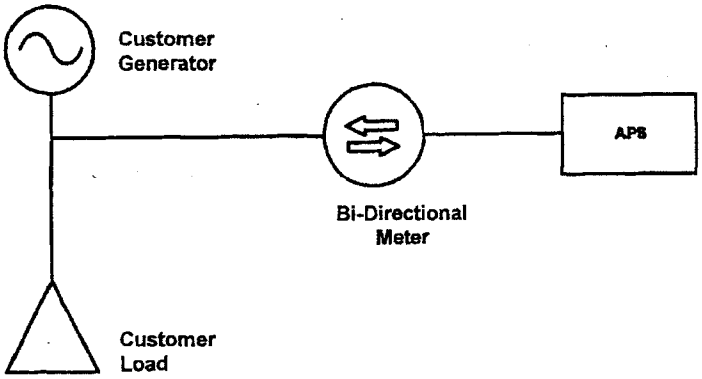
TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection requirements for Distributed Generation. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to ~~supplemental or~~ special terms and conditions as provided for in a customer interconnection or Supply/Purchase agreement.~~pursuant to the customer's Purchase Agreement with the Company.~~

~~The customer and the Company will share in the cost of the bi-directional meter used to record sales to the customer and purchases from the customer. The Company shall be responsible for all costs up to and equal to the installed cost of a residential time-of-use meter, and the customer shall be responsible for the difference between the installed cost of the bi-directional meter compared to a standard residential time-of-use meter. The customer shall have the option to pay the incremental metering costs initially or in monthly installments over a five year time period.~~

METERING CONFIGURATION





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 premises served and when all applicable provisions described herein have been met.

APPLICATION

This rate schedule is applicable to any general service customer having generation equipment 100 kW and greater capable of supplying all or a portion of its power requirements for other than emergency purposes requiring supplemental, maintenance, and/or standby power. Direct access customers are not eligible for service under this rate schedule.

RATES

The bill shall be the sum of the amounts computed under A, B, and C below, including any applicable adjustments:

A. Basic Service: The Basic Service and Revenue Cycle Service Charges included in the customer's applicable General Service rate schedule will continue to apply.

B. Supplemental Service: Supplemental service will be provided in accordance with the rate levels contained in the customer's applicable General Service rate schedule, excluding the monthly Basic Service and Revenue Cycle Service Charges.

C. Standby and Maintenance Service: The monthly charge for Standby and Maintenance Service shall be the sum of:

(1) Demand Charge:

The unbundled transmission charge, if applicable, contained in the Customer's otherwise applicable General Service rate schedule plus the unbundled delivery charge contained in the customer's applicable General Service rate schedule. This summation is then multiplied by the amount of Contract Standby Capacity.

(2) Energy Charge:

The unbundled transmission charge, if applicable, contained in the Customer's otherwise applicable General Service rate schedule plus the per kWh monthly firm power purchase rates shown in rate schedule EPR-2.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

A. Supplemental Demand:

Supplemental demand shall be the highest 15-minute interval during the billing month which shall equal the (a) 15-minute integrated kW demand calculated for every 15-minute interval as recorded on the Supply Meter, plus (b) the simultaneous 15 minute measured kW output of the of each customer self-generation as recorded on the Generator Meter(s), less (c) the aggregate Contract Standby Capacity of all the customer's generating units; however, the result shall never be less than zero (0) for purposes of determining Supplemental Demand. If Company authorized scheduled maintenance was being performed on any of the customer's generators at the

time of the highest 15 minute interval during the billing month, the amount of demand recorded on the Supply Meter shall be reduced by the applicable Maintenance Power Level of the generator unit(s) undergoing authorized scheduled maintenance for purposes of calculating supplemental demand used for billing.

Customer's maximum Supplemental Service kW requirements shall not exceed that established in the Electric Supply Agreement.

B. Supplemental Energy:

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply Meter, less any energy determined to be either Standby or Maintenance energy as defined in this Schedule.

DETERMINATION OF CONTRACT STANDBY CAPACITY

For each specific customer generating unit for which the Company is providing Standby Service, Contract Standby Capacity shall be the greater of a) the measured kW output of each customer generation unit at time of start-up test, or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed Customer's actual total load.

DETERMINATION OF STANDBY AND MAINTENANCE ENERGY

Standby and Maintenance Energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full outages, unscheduled partial outages, and scheduled maintenance periods of said facility.

When the sum of the energy measured on both the Supply and Generator(s) Meters during simultaneous periods is greater than the maximum energy output of the generator(s) at Contract Standby Capacity, the Standby Energy shall be equal to the summation of the differences between the maximum energy output of the generator(s) at Contract Standby Capacity and the energy measured on the Generator Meter(s) for every 15-minute interval of the month. When the sum of the energy measured on both the Supply and Generator(s) Meter is equal to or less than the maximum energy output of the generator(s) at Contract Standby Capacity, then the Standby energy shall be that energy measured on the Supply Meter.

MAINTENANCE REQUIREMENTS

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per generation unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months. Customer shall provide Company with its planned maintenance schedule 90 days in advance of any planned maintenance in order for the Company to coordinate customer's scheduled maintenance with that of the Company. Upon review, Company shall either approve customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

TERMINATION PROVISION

Should Customer cease to operate his generation unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

TERMS AND CONDITIONS

Customer must enter into an Agreement for the Interconnection and The Sale of Power with Company and an Electric Supply Agreement which shall establish all pertinent details related to interconnection and other required service standards. Customer will not have the option to sell power and energy to Company under this tariff. Should Customer desire to do so, Customer would be required to enter into a new Service Agreement which would set forth the applicable purchase rate in addition terms and conditions for interconnection and for the sale of power to the Company.

Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

SOLAR PARTIAL REQUIREMENTS 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 premises served and when all applicable provisions described herein have been met.

APPLICATION

This rate schedule is applicable to any general service customer having solar/photovoltaic generation equipment with a nameplate service continuous rating of greater than 100 kW but less than 1000 kW capable of supplying all or a portion of its power requirements. Direct access customers are not eligible for service under this rate schedule.

RATES

The bill shall be the sum of the amounts computed under A, B, and C below, including any applicable adjustments:

A. Basic Service: The Basic Service and Revenue Cycle Service Charges included in the customer's applicable General Service rate schedule will continue to apply

B. Supplemental Service: Supplemental service will be provided in accordance with the rate levels contained in the customer's applicable General Service rate schedule, excluding the monthly Basic Service and Revenue Cycle Service Charges.

C. Standby Service: The monthly charge for standby service shall be calculated as follows:

The unbundled delivery charge contained in the customer's applicable General Service rate schedule is multiplied by the 15 minute integrated kW measured on the Generator Meter during the customer's monthly peak demand.

METERING

The Company will install, at the customer's expense, a bi-directional meter at the point of delivery to the customer (Supply Meter) and meter(s) at the point(s) of output from each of the customer's generators (Generator Meter). All meters will record integrated demand and energy on the same 15- minute interval basis as specified by the Company.

PAYMENT FOR PURCHASES FROM THE CUSTOMER

The Company will pay the Customer for any energy purchased at the per kWh monthly non-firm purchase rates as shown in rate schedule EPR-2.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

A. Supplemental Demand:

Supplemental demand shall be the highest 15-minute integrated kW demand as recorded on the Supply Meter during the billing period.

B. Supplemental Energy:

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply Meter.

DETERMINATION OF CONTRACT STANDBY CAPACITY

For each specific customer generating unit for which the Company is providing Standby Service, monthly Contract Standby Capacity shall be the simultaneous 15 minute integrated kW demand as recorded on the Generator Meter(s) at the time the customer's Supply Meter registers the highest 15 minute integrated kW demand during the billing period.

TERMINATION PROVISION

Should Customer cease to operate his generation unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

TERMS AND CONDITIONS

Customer must enter into an Agreement for the Interconnection and The Sale of Power with Company and an Electric Supply Agreement which shall establish all pertinent details related to interconnection and other required service standards. Customer will not have the option to sell power and energy to Company under this schedule. Should Customer desire to do so, Customer would be required to enter into a new Service Agreement which would set forth the applicable purchase rate in addition to terms and conditions for interconnection and for the sale of power to the Company.

Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS, that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

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.

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 day the request is being made, and Company agrees to work the request on the same 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 Customers will be charged for work such as metering equipment installations, including instrument transformers (excluding meters), maintenance or planned outages requested by the Customer , 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.

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.

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 Establishment of Credit - Company shall not require a security deposit from a new applicant for service 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.

2.5.2 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 Nonresidential 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 Eestablishment 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 Nonresidential - Company may require a nonresidential 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.

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 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 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 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.

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.

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.

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 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

4.3.2.1 Refunds 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 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.

4.4 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.

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 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 - 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, 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 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 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 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.

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 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.

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;
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 Schedule 8, Bill Estimation, as filed with 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 will be billed for the estimated energy and, if applicable, demand, for the period in which the energy eversion took place. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer 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, Condominiums - 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 – Company will allow master metering for high rise 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.

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 The existence of an obvious 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.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

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.

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.

~~1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.~~

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.

~~2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.~~

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. ~~Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.~~

~~The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.~~

2.2.1 The customer ~~may~~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 ~~meter panel~~the point of delivery.

2.2.2 The customer ~~may~~will additionally be required to pay an after-hours charge of $75.00 ~~should~~if the customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established ~~during a period other than regular working hours, or on the same day of their request,~~after 5:00 p.m. on a day other than the day of request.

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 day the request is being made, and Company agrees to work the request on the same 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 Customers will be charged for work such as metering equipment installations, including instrument transformers (excluding meters), maintenance or planned outages requested by the Customer , 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.,

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.

~~2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be $75.00 per hour.~~

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.

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 Establishment of Credit - Company shall not require a security deposit from a new applicant for service 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.

2.5.2 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 Nonresidential Establishment of Security Deposit ~~- All nonresidential customers may~~ - All non-residential applicants will be required to~~:2.5.3.1 - Place~~ place a cash deposit to secure payment of bills for service as prescribed herein, ~~or~~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 ~~Provide~~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 E~~R~~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 Nonresidential - Company may require a nonresidential 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.

2.7.2 ~~2.7.1~~ Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by ~~the~~ Company in accordance with this section:

~~2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,~~

2.7.2.1 ~~2.7.1.2~~ 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 ~~2.7.1.3~~ 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 ~~APS~~Company is providing bundled electric service.

~~2.7.2 Separate security deposits may be required for each service location.~~

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 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 two (2) times the customer's average monthly bill as estimated by Company for the services being provided by ~~the~~ Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited 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.

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 ~~being served on a Standard Offer rate~~receiving bundled service, Company will use reasonable care in initially establishing service to the customer under the most advantageous ~~Standard Offer~~ 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 ~~Standard Offer~~ Optional Rates – Certain optional ~~Standard Offer~~ 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. ~~A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company.~~ Billing under the alternate rate will become effective from the next regularly scheduled meter reading, ~~or when~~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 ~~rate selection~~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.

3.5 Any customer ~~making a~~that selects Direct Access ~~rate selection~~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~~~~nineteen (15~~19) fifteen (15) calendar days from the billing date. Any payment not received within this time frame ~~shall~~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 ~~services~~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.

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 ~~the~~ 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 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. ~~Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company 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. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.~~

4.3.2.1 Refunds 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.

~~4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to $10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.~~

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 last Company obtained meter read date.

~~4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.~~

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.

4.4 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 ~~shall~~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 ~~4.5 Field Call Charge~~ Company ~~may~~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 ~~of~~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.

~~4.5.1~~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 ~~4.5.2~~ To avoid termination of service, the customer ~~may~~will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company ~~may~~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 ~~if~~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 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 - 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, 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 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 ~~existing~~ 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 is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter plus~~and~~ the cost incurred to install the specialized meter 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.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of ~~the~~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 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 ~~assure~~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. ~~The 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. In situations where Company suspects that a customer's load has a non-conforming 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 power factor of less than 90%, or leading, or other detrimental conditions shall be required to remedy problems in order to achieve a power factor in conformance with above standards, 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, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs~~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.

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 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.~~

6.1.2 ~~6.1.3~~ 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 ~~be charged~~result in charge to the MSP of the replacement costs ~~less five (5) years depreciation,~~ 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;
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. ~~In the event~~If Company must temporarily replace the MSP's meter and/or associated metering equipment ~~as necessary~~ 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 ~~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. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider.~~ 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. ~~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 credentials~~

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.~~10). Where energy and, if applicable, demand is estimated by Company, estimation will be in accordance with Company's Schedule 8, Bill Estimation, as filed with 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 will be billed for the estimated energy ~~consumption~~and, if applicable, demand, for the period in which the energy eversion took place.~~that would have registered had all energy and demand usage been properly metered.~~ Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer ~~may~~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 ~~6.4.4 Customer will be billed~~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 ~~shall~~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, Condominiums ~~and Other Multiunit Residential Buildings~~ - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered ~~unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.~~ unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205. 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 – Company will allow master metering for high rise 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.

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 The existence of an obvious 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.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

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.

RATE SCHEDULE E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT 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. Customers may not receive discounts under this schedule and Rate Schedule E-4 Medical Support Care Program concurrently.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Residential Energy Support Program pursuant to Arizona Corporation Commission Decision Nos. 55931, 56680 and xxxxx. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

A.

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 400 kWh	40%
401 – 800 kWh	26%
801 – 1200 kWh	14%
1201 kWh and above	$13.00

B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.

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. Customers may not receive discounts under this schedule and Rate Schedule E-4 Medical Support Care Program concurrently.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Residential Energy Support Program pursuant to Arizona Corporation Commission Decision Nos. 55931, ~~and~~ 56680 and xxxxx. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

A.

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 400 kWh	40%
401 – 800 kWh	26%
801 – 1200 kWh	14%
1201 kWh and above	$13.00

B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.

RATE SCHEDULE E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT 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. Customers may not receive discounts under this schedule and Rate Schedule E-3 Energy Support Program concurrently.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Medical Care Equipment Program pursuant to Arizona Corporation Commission Decision Nos. 59222 and xxxxx. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

A.

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 800 kWh	40%
801 – 1400 kWh	26%
1401 – 2000 kWh	14%
2001 kWh and above	$26.00

B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.

RATE SCHEDULE E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT 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. Customers may not receive discounts under this schedule and Rate Schedule E-3 Energy Support Program concurrently.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Medical Care Equipment Program pursuant to Arizona Corporation Commission Decision Nos. 59222 and xxxxx. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

A.

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 800 kWh	40%
801 – 1400 kWh	26%
1401 – 2000 kWh	14%
2001 kWh and above	$26.00

B. Adjustment Schedule PSA-1 will not apply to customers served under this rate schedule.

I. GENERAL DESCRIPTION:

This Plan for Administration outlines APS' implementation of the ACC's ordered "lifeline" rate discount program for low-income residential customers (Energy Support Program, Rate E-3). The Plan is pursuant to Decision Nos. 55931 dated 04/01/1988, 56680 dated 10/25/1989, and xxxxx dated xx/xx/xxxx.

II. ELIGIBILITY FOR DISCOUNT:

1. Income Eligibility for the discount is administered by the Arizona Department of Economic Security (DES) and other community action agencies that apply the income eligibility guidelines specified in the Company's Rate Schedule E-3. Applications written in both Spanish and English will be available in a number of locations including food banks, Salvation Army offices and community action agencies.
2. After a customer is approved by the Department of Economic Security or other community action agency for this program, their name will be forwarded to APS in order for the discount to be applied to their bill.
3. Each application is good for a 12 month period. Annual recertification by the DES will be required for the discount to be extended beyond one year.
4. Criteria for eligibility for the discount under the Energy Support Program is outlined in the APS Energy Support Program (E-3) Self-Declaration Application.
5. Customers must be billed under an APS residential rate schedule in order to qualify for the discount.
6. Customers may not receive discounts under both the Residential Energy Support Program (E-3) and the Medical Care Equipment Program (E-4) concurrently.

III. DISCOUNT LEVELS:

Discounts under the Energy Support Program are specified in the Company's Rate Schedule E-3.

IV. FUTURE CONSIDERATIONS:

The Company will update their applications for the program and information brochures as changes take place in guideline income levels and other externalities which may affect this program.

V. ATTACHMENTS:

Attached are copies of the following documents that are pertinent to the administration of the program:

1. Applications for the APS Energy Support Program (E-3), written in English and Spanish;
2. A bilingual informational brochure;
3. The Company's Rate Schedule E-3 which specifies applicable discounts;
4. An announcement suitable for posting which provides the present income qualifications for the program;
5. Listing of agencies where applications can be obtained.

Attachment GAD-13RB

ARIZONA PUBLIC SERVICE COMPANY

Plan for Administration
Of
Residential Energy Support Program (E-3)
Pursuant to ACC Decision Numbers 55931 dated 04/01/88
56680 dated 10/25/89
XXXXX dated XX/XX/XX

Effective ~~October 25, 1989~~XX/XX/XXX

I. GENERAL DESCRIPTION:

This Plan for Administration outlines APS' implementation of the ACC's ordered "lifeline" rate discount program for low-income residential customers (Energy Support Program, Rate E-3).

II. ELIGIBILITY FOR DISCOUNT:

1. Income Eligibility for the discount is administered by the Arizona Department of Economic Security (DES) and other community action agencies that apply the income eligibility guidelines specified in the Company's Rate Schedule E-3. Applications written in both Spanish and English will be available in a number of locations including food banks, Salvation Army offices and community action agencies.
2. After a customer is approved by the Department of Economic Security or other community action agency for this program, their name will be forwarded to APS in order for the discount to be applied to their bill.
3. Each application is good for a 12 month period. Annual recertification by the DES will be required for the discount to be extended beyond one year.
4. Criteria for eligibility for the discount under the Energy Support Program is outlined in the APS Energy Support Program (E-3) Self-Declaration Application.
5. Customers must be billed under ~~residential rates E-10 or E-12~~an APS residential rate schedule in order to qualify for the discount.
6. Customers may not receive discounts under both the Residential Energy Support Program (E-3) and the Medical Care Equipment Program (E-4) concurrently.

III. DISCOUNT LEVELS:

Discounts under the Energy Support Program are specified in the Company's Rate Schedule E-3.

IV. FUTURE CONSIDERATIONS:

The Company will update their applications for the program and information brochures as changes take place in guideline income levels and other externalities which may affect this program.

V. ATTACHMENTS:

Attached are copies of the following documents that are pertinent to the administration of the program:

1. Applications for the APS Energy Support Program (E-3), written in English and Spanish;
2. A bilingual informational brochure;

3. The Company's Rate Schedule E-3 which specifies applicable discounts;
4. An announcement suitable for posting which provides the present income qualifications for the program;
5. Listing of agencies where applications can be obtained.

I. GENERAL DESCRIPTION:

This Plan for Administration outlines APS' implementation of a rate discount program for low-income residential customers where medical care equipment essential for sustaining life is in use within the customer's premise.

II. ELIGIBILITY FOR DISCOUNT:

Customer must meet Rate E-3 criteria which is:

1. Income eligibility for the discount is administered by the Arizona Department of Economic Security (DES) and other community action agencies that apply the income eligibility guidelines specified in the Company's Rate Schedule E-3. Applications written in both Spanish and English will be provided in a number of locations including food banks, Salvation Army Offices and community action agencies.
2. After a customer is approved by the Department of Economic Security or other community action agency for this program, their name will be forwarded to APS in order for the discount to be applied to their bill.
3. Each application is good for a 12 month period. Annual recertification by the DES will be required for the discount to be extended beyond one year.
4. Criteria for eligibility for the discount under the Energy Support Program is outlined in the APS Energy Support Program (E-3) Self-Declaration Application.
5. Customers must be billed under an APS residential rate schedule.
6. Customers may not receive discounts under both the Residential Energy Support Program (E-3) and the Medical Care Equipment Program (E-4) concurrently.

In addition to meeting the E-3 eligibility requirements, APS must have a signed statement of verification of medical care equipment. The verification must be signed by the physician responsible for the care of the individual living at the premise where medical care equipment is required. The medical care equipment must be in use, and "essential" to the sustaining of life of an individual living within the premise. Essential is defined as "medical equipment where discontinuance of service from the equipment for a period longer than four (4) hours could be especially dangerous to an individual's health."

Annual reverification by the physician will be required for the discount to be extended beyond one year.

III. DISCOUNT LEVELS:

Discounts under the Medical Care Program are specified in the Company's Rate Schedule E-4.

IV. QUALIFIED MEDICAL CARE EQUIPMENT:

Use of the following equipment will qualify for the E-4 program:

Ventilator
Oxygen Concentrator
Peritoneal Dialysis Cycler
Hemo Dialysis Equipment
Feeding Pump
Infusion Pump
Suction Machine
Small Volume Nebulizer
Oximeter

V. FUTURE CONSIDERATIONS:

The Company will update their applications for the program and information brochures as changes take place in the guideline levels and other externalities which may affect this program.

VI. ATTACHMENTS:

The Company's Rate Schedule E-4 which specifies applicable discounts.
Customer notification.
F.Y.I. Notice to Arizona Community Action Associates, DES, and Human Services Magazine.

Attachment GAD-14RB

ARIZONA PUBLIC SERVICE COMPANY

PLAN FOR ADMINISTRATION OF MEDICAL CARE EQUIPMENT PROGRAM

GENERAL DESCRIPTION:

This Plan for Administration outlines APS' implementation of a rate discount program for low-income residential customers where medical care equipment essential for sustaining life is in use within the customer's premise.

ELIGIBILITY FOR DISCOUNT:

Customer must meet Rate E-3 criteria which is:

1. Income eligibility for the discount is administered by the Arizona Department of Economic Security (DES) and other community action agencies that apply the income eligibility guidelines specified in the Company's Rate Schedule E-3. Applications written in both Spanish and English will be provided in a number of locations including food banks, Salvation Army Offices and community action agencies.
2. After a customer is approved by the Department of Economic Security or other community action agency for this program, their name will be forwarded to APS in order for the discount to be applied to their bill.
3. Each application is good for a 12 month period. Annual recertification by the DES will be required for the discount to be extended beyond one year.
4. Criteria for eligibility for the discount under the Energy Support Program is outlined in the APS Energy Support Program (E-3) Self-Declaration Application.
5. Customers must be billed under ~~a~~ an APS residential rate schedule.
6. Customers may not receive discounts under both the Residential Energy Support Program (E-3) and the Medical Care Equipment Program (E-4) concurrently.

In addition to meeting the E-3 eligibility requirements, APS must have a signed statement of verification of medical care equipment. The verification must be signed by the physician responsible for the care of the individual living at the premise where medical care equipment is required. The medical care equipment must be in use, and "essential" to the sustaining of life of an individual living within the premise. Essential is defined as "medical equipment where discontinuance of service from the equipment for a period longer than four (4) hours could be especially dangerous to an individual's health."

Annual reverification by the physician will be required for the discount to be extended beyond one year.

DISCOUNT LEVELS:

Discounts under the Medical Care Program are specified in the Company's Rate Schedule E-4.

QUALIFIED MEDICAL CARE EQUIPMENT:

Use of the following equipment will qualify for the E-4 program:

Ventilator
Oxygen Concentrator
Peritoneal Dialysis Cycler
Hemo Dialysis Equipment
Feeding Pump
Infusion Pump
Suction Machine
Small Volume Nebulizer
Oximeter

FUTURE CONSIDERATIONS:

The Company will update their applications for the program and information brochures as changes take place in the guideline levels and other externalities which may affect this program.

ATTACHMENTS:

The Company's Rate Schedule E-4 which specifies applicable discounts.
Customer notification.
F.Y.I. Notice to Arizona Community Action Associates, DES, and Human Services Magazine.

EXHIBIT
APS-39
admitted

REJOINDER TESTIMONY OF GREGORY A. DeLIZIO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

October 4, 2006

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REJOINDER TESTIMONY OF GREGORY A. DeLIZIO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E-01345A-05-0827)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gregory A. DeLizio. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU FILE DIRECT AND REBUTTAL TESTIMONY IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. My Rejoinder Testimony shall address comments and recommendations made by Staff and other parties in their Surrebuttal Testimony concerning the Company's proposals for an Environmental Improvement Charge ("EIC"), a net metering rate (EPR-5), and rates for partial requirements service (revised EPR-2, E-56 and E-57).

Q. DOES YOUR SILENCE REGARDING ANY OF THE ISSUES DISCUSSED BY OTHER PARTIES INDICATE AN ACCEPTANCE OF THOSE POSITIONS BY THE COMPANY?

A. No, it does not. For those issues, the Company maintains its positions discussed in previous testimony.

II. SCHEDULE EIC - ENVIRONMENTAL IMPROVEMENT CHARGE

Q. PLEASE SUMMARIZE THE SURREBUTTAL TESTIMONY OF STAFF AND OTHER PARTIES CONCERNING THE EIC?

A. Staff and the Residential Utility Consumer Office ("RUCO") address the EIC in

their Surrebuttal Testimony, but they do not offer any new information justifying their opposition to the EIC, nor do they substantively rebut any of the additional information concerning the EIC provided in my Rebuttal Testimony or the Rebuttal Testimony of Company witness Ed Fox. Intervenor Western Resource Advocates ("WRA") continues to support the EIC, including the changes that were proposed in the Rebuttal Testimony of Mr. Fox.

III. ADJUSTMENT SCHEDULE EPS-1 ENVIRONMENTAL PORTFOLIO STANDARD

Q. DO STAFF AND OTHER PARTIES AGREE WITH THE PROPOSED CHANGE TO SCHEDULE EPS-1?

A. Yes. RUCO and AECC agree with the proposed change to Schedule EPS-1, as set forth in my Rebuttal Testimony and the testimony of Staff witness Barbara Keene, which funds an additional $4.25 million EPS revenue requirement approved in Decision No. 68668. No party opposes the proposed change.

IV. NET METERING RATE EPR-5

Q. PLEASE SUMMARIZE THE SURREBUTTAL TESTIMONY OF STAFF AND OTHER PARTIES CONCERNING SCHEDULE EPR-5 (NET METERING).

A. Solar Advocates witness Ed Smeloff continues to advocate that customers with renewable power generators up to 2 MW in size should be allowed to participate in the Company's net metering program. The Company's proposed cap on individual generator size is 10 kW. Mr. Smeloff opposes the recovery of net lost revenues associated with the net metering program. Mr. Smeloff supports the Company's proposal to use a single bi-directional meter for net metering. No other party provided additional testimony on the Company's proposed net metering program.

Q. DO YOU AGREE WITH MR. SMELOFF'S RECOMMENDATION ON

THE PROPOSED CAP?

A. No. In his Rebuttal Testimony, Mr. Smeloff offers no new information or credible reasons to justify his proposed 2 MW cap on individual generators for the net metering program. Furthermore, Mr. Smeloff attempts to defend his recommendation with a somewhat inappropriate comparison of distributed generation to energy conservation and an over-stated distinction between "net metering" and "net billing", which the Company believes is not really relevant given the types of distributed renewable energy systems that are being installed in Arizona and the amount of excess power that is typically being generated by customers.

Q. PLEASE EXPLAIN YOUR LAST STATEMENT.

A. As I described in my Rebuttal Testimony, both net metering and net billing allow the customer to supply their own energy needs with a qualifying generator. At any given time, if the customer's generation is greater than their load, the excess power flows back to the grid and is compensated by the Company. The difference is that under net billing excess power is purchased at an avoided cost rate, while under net metering the excess power is credited against power that the customer purchases from the Company in future billing periods and is therefore compensated at full retail rates. Under both net metering and net billing the Company provides backup service in case the customer's generator has an outage, but does not charge the customer the cost for backup service.

Mr. Smeloff portrays the distinction between net metering and net billing as a make or break situation: customers would install renewable generators under net metering, but not under net billing, supposedly because the customer benefits of the former are far superior to the latter. However, the Company believes that this

is simply not the case. Almost all of the customer renewable generators that are currently participating in the Company's net billing rates, and that are expected to participate in the net metering program, are solar photovoltaic systems, which due to their expense, are typically sized to service only a portion of the customer's energy needs. As a result, very little excess power is being generated for sale to APS at any rate.

For example, during the test year customers on our net billing rates, EPR-2 and EPR-4, purchased 2,298 kWh per month on average from the Company and sold back 94 kWh per month. In other words, the excess power was only 4% of the customer's purchases and even a smaller percent of their load. As a result, the difference in financial benefit to the customer between net metering and net billing would probably only amount to a few dollars per month for a typical customer. In fact, the financial benefits from federal and state tax credits and the Company's Solar Partners Incentive Program are undoubtedly much more important for a customer's decision to invest in renewable generation.

Q. WHAT ABOUT MR. SMELOFF'S COMPARISON OF DISTRIBUTED GENERATION TO ENERGY CONSERVATION?

A. Mr. Smeloff argues that the economic impact of distributed generation to a utility and its customers is exactly the same as energy conservation. He equates installing a distributed generation system to installing an energy efficient appliance or unplugging a refrigerator in the garage. We assume the latter also involves removing the refrigerator. The Company does not have a program that encourages customers merely to unplug an appliance because these "nega-watts" would be too unreliable and therefore provide little value to the Company or its customers (the customer could obviously just plug the appliance back in).

Therefore, Mr. Smeloff concludes that there should not be any artificial caps on the net metering program or additional costs imposed on customers with distributed generation.

The Company believes that this line of reasoning is faulty and potentially misleading. In fact, there is at least one key difference between distributed generation and energy conservation that would merit differential treatment. This key difference involves the nature of what happens during a failure of the customer's generator or appliance. When an energy efficient appliance or other conservation measure fails (i.e. stops working) the customer's associated load is also removed, which reduces the utility's system load and their instantaneous generation requirement. Conversely, when a distributed generation unit incurs an outage, the customer's associated load is typically not reduced; the utility's load would actually increase creating an additional instantaneous burden on power generation. In other words, the Company would have to backup the customer's generator with generation, transmission, and distribution capacity, while the Company would not have to backup an energy conservation measure. Under the Company's proposed net metering program, the customer is not charged for this backup service, which is one of the reasons that we believe that it should only be offered for smaller renewable distributed generators with a maximum nameplate rating of 10 kW.

Q. DOES THE COMPANY AGREE WITH MR. SMELOFF'S RECOMMENDATION ON THE RECOVERY OF NET LOST REVENUES FROM THE NET METERING PROGRAM?

A. No. Mr. Smeloff opposes the recovery of net lost revenue from the Company's proposed net metering program and claims that such recovery is unnecessary because the Company is experiencing rapid growth. His reasoning appears to be

that because the Company's energy sales and revenue are growing, we shouldn't be concerned about losing sales and revenues from a net metering program, which encourages customers to generate their own power. The Company believes that Mr. Smeloff's argument misses the point. Whether APS sales are growing, remaining flat, or declining, they will be less than they would have been absent the distributed generator. The Company's rapid growth also carries with it the additional costs to serve our increasing customer base. This additional financial burden heightens, not lessens, the importance of preserving the margins from customers participating in public benefit programs like net metering.

Q. WHAT DOES THE COMPANY RECOMMEND?

A. The Company continues to recommend the net metering program proposed in my Direct Testimony, which includes the cap of 10 kW on individual generator size. As discussed in my Rebuttal Testimony, this requirement is consistent with industry practice, and the Company has net billing and other standby rates to accommodate customers with larger generators. The Company also continues to recommend the recovery of net lost revenues associated with the net metering program for reasons discussed in my Direct and Rebuttal Testimony.

V. RATES FOR PARTIAL SERVICE REQUIREMENTS

Q. WHAT WERE OTHER PARTIES COMMENTS ON APS' PARTIAL REQUIREMENT RATES?

A. Staff began their review of the proposed partial requirements rates, E-56 and E-57 and does not have any concerns so far. No other party commented on or opposes the proposed changes to the Company's partial requirement rates.

VI. SERVICE SCHEDULE 1

Q. WHAT ARE THE TOPICS DISCUSSED BY STAFF WITNESS

ANDREASEN THAT YOU ARE ADDRESSING?

A. I address Staff's proposed clarification to Service Schedule 1.

Q. PLEASE DISCUSS THE STAFF PROPOSED CLARIFICATION TO SCHEDULE 1.

A. Ms. Andreasen recommends in her testimony that APS should include a definition for Multi-Unit Residential High-Rise Developments on Schedule 1.

Q. DO YOU AGREE WITH HER RECOMMENDATIONS?

A. Yes. The Company will add the definition and it will be identical to that incorporated within the Company's proposed definition for Multi Unit Residential High Rise Developments proposed in Schedule 3 as supported by Witness Rumolo. Assuming the Commission approves Schedule 1 as modified, we will include Staff's changes in our tariff compliance filing at the conclusion of the case.

VII. CONCLUSION

Q. WOULD YOU PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY?

A. The Company does not believe that Staff or RUCO provide any additional information or credible reasons to justify their opposition to the proposed EIC charge. Therefore, APS recommends that the Commission approve the EIC charge as proposed by the Company. The Company does not believe that any party provides new information or justification to modify the Company's proposed net metering rate and continues to recommend that the Commission approve the rate as proposed. While Staff has not completed their review of the Company's proposed partial requirements rates, they have not found any issues to date. No other party opposes the rates. Therefore, the Company recommends that

the Commission approve the Company's proposed partial requirements rates.

Q. DOES THAT CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes, it does.

SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)
RESPONSES TO ARIZONA PUBLIC SERVICE COMPANY'S
SECOND SET OF DATA REQUESTS
APS RATE CASE DOCKET NO. E-01345A-05-0816
SEPTEMBER 29, 2006

APS-SWEEP-2-6 Please provide a copy of the goal adopted by the Western Governors Association to increase energy efficiency, referenced at page 5 of your testimony.

RESPONSE: I provided the Western Governors Association (WGA) Policy Resolution 06-10, dated June 11, 2006, to APS in August 2006, in response to the letter from Deborah Scott requesting parties to submit workpapers and studies associated with direct testimony. The energy efficiency goal, adopted by the WGA, is on the first page of the WGA Policy Resolution. The Western Governors adopted the Policy Resolution on June 11, 2006.

In addition, the WGA energy efficiency goal was supported by the work of the Clean and Diversified Energy Advisory Committee (CDEAC) and its Energy Efficiency Task Force. I have included the Energy Efficiency Task Force Report, January 2006, as a supporting document in response to the APS data request (see the file labeled SWEEP_ResponseAPS2-6_WGA_CDEAC_EE). The WGA energy efficiency goal is discussed on page x, and the report documents that the goal of 20% savings by 2020 is achievable.

EXHIBIT
APS-40
admitted

Clean and Diversified Energy Initiative

WESTERN GOVERNORS' ASSOCIATION

Energy Efficiency Task Force Report

January 2006

Western Governors' Association
Clean and Diversified Energy Initiative

Energy Efficiency Task Force Report

The Western Governors' Association's Clean and Diversified Energy Advisory Committee (CDEAC) commissioned this task force report in February 2005. Members of the Task Force are listed below. This is one of several task force reports presented to the CDEAC on December 8, 2005 and accepted for further consideration as the CDEAC develops recommendations for the Governors. While this task force report represents the consensus views of the members, it does not represent the adopted policy of WGA or the CDEAC. At their Annual Meeting in June, 2006, Western Governors will consider and adopt a broad range of recommendations for increasing the development of clean and diverse energy, improving the efficient use of energy and ensuring adequate transmission. The CDEAC commends the Task Force for its thorough analysis and thoughtful recommendations.

Members of the Energy Efficiency Task Force

Howard Geller (Chair)	Southwest Energy Efficiency Project
Michele Barlow	Wyoming Outdoor Council
Jeff Burks	Public Service Co. of NM Resources
Joshua Bushinsky	Pew Center on Global Climate Chang
Sheryl Carter	Natural Resources Defense Council
Donald D. Gilligan	Predicate
Roger Duncan	Austin Energy
Sue Gander	U.S. Environmental Protection Agency
Mike Koszalka	PacifiCorp
Kurt Maurer	Arizona Dept. of Environmental Quality
Harry Misuriello	Alliance to Save Energy
Kate Offringa	North American Insulation Manufacturers Assn.
Amanda Ormond	Consultant, Grand Canyon Trust
Steve Owens	Arizona Dept. of Environmental Quality (CDEAC member)
Bill Real	PNM (CDEAC member)
Luis A. Reyes	Kit Carson Electric
John Ryan	Washington State University Energy Program
Soll Sussman	Texas General Land Office
Malcolm Verdict	Energy Systems Laboratory
Dick Watson	Consultant

Facilitator

Toni Martorelli	STAR Group, LLC

Consultants

Alison Bailie	Tellus Institute
Lazarus Michael	Tellus Institute
Ron Judkoff	National Renewable Energy Laboratory

Quantitative Working Group

The quantitative working group was created by the CDEAC to compare the analysis of data among task forces in order to ensure consistency in assumptions across the reports. The following members contributed to this report:

Doug Arent	National Renewable Energy Laboratory
John Tschirhart	Department of Economics, University of Wyoming
Dick Watson	Quantitative Working Group

Preface

This report was prepared by the Energy Efficiency Task Force convened by the Western Governors' Association (WGA) under the auspices of its Clean and Diversified Energy Advisory Committee. The members of the Energy Efficiency Task Force are listed in Appendix A. The Executive Summary and Chapters I and III of this report were drafted by Howard Geller, Task Force Chairperson. Chapter II was drafted primarily by Alex Schroeder of the WGA staff and Howard Geller. Chapter IV was drafted primarily by Sheryl Carter and Devra Wang of the Natural Resources Defense Council, with assistance from Howard Geller. Chapter V was drafted primarily by Alison Bailie and Michael Lazurus of the Tellus Institute, with assistance from Howard Geller and David Weitz of the Building Codes Assistance Project. Chapter VI was drafted primarily by Amanda Ormond, consultant to the Grand Canyon Trust, and Howard Geller, with assistance from Kate Offringa of the North American Insulation Manufacturers Association. Mark Ruzzin of the Southwest Energy Efficiency Project provided editorial assistance.

The U.S. Environmental Protection Agency funded the analytical portion of the Task Force effort, the results of which are presented in Chapter V. Task Force members appreciate the generous financial support provided by the U.S. EPA.

This report represents the work of the Energy Efficiency Task Force of the Clean and Diversified Energy Advisory Committee. It does not represent the adopted policies or views of the Western Governors' Association or the Clean and Diversified Energy Advisory Committee.

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Executive Summary

The western United States contains the fastest growing states in the country in terms of population and energy consumption. For the region as a whole, electricity sales increased 1.7% per year on average during 1990-2003.[1] But electricity use in Nevada climbed nearly 5% per year and electricity use in Arizona, Colorado, North Dakota, and Utah increased more than 3% per year during this period. Rapid growth in electricity demand presents a number of challenges for the region including high investment requirements in new generation, transmission and distribution facilities, increasing risk of power shortages, increasing water consumption, and more harmful emissions by power plants.

Increasing the efficiency of energy use in western states will provide a broad range of benefits, including:

- saving consumers and businesses money on their energy bills;
- reducing dependence on imported fuel sources;
- reducing vulnerability to energy price spikes;
- reducing peak demand and improving the utilization of the electricity system;
- reducing the risk of power shortages;
- supporting local businesses and stimulating economic development;
- enabling avoidance of the most controversial energy supply projects;
- reducing water consumption by power plants; and
- reducing pollutant emissions by power plants and improving public health.

In short, increasing energy efficiency is our cleanest, cheapest, least risky, and least controversial energy resource. And increasing energy efficiency is a "win-win strategy" for consumers, businesses, utilities, and the environment in western states.

Some western states have taken significant steps to increase the efficiency of energy use in recent years. This report reviews these "best practice" energy efficiency efforts.[2] It also reviews energy efficiency potential studies that have been completed in states that belong to the Western Governors' Association (WGA) in recent years as well as barriers to greater energy efficiency. We then analyze the impacts of current energy efficiency policies and programs, as well as the potential benefits of widespread adoption of "best practice" policies and programs. **We find that it is feasible to reduce electricity use 20% from projected levels in 2020, and do so cost effectively, through full deployment of best practice policies and programs.** This is the energy efficiency goal enunciated in the 2004 WGA clean and diversified energy resolution. The final chapter of the report provides our energy efficiency policy recommendations.

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[1] The 18 western states that belong to the WGA and are included in this report are Alaska, Arizona, California, Colorado, Hawaii, Idaho, Kansas, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon,S outh Dakota, Texas, Utah, Washington,a nd Wyoming.

[2] Our report focuses primarily on electricity efficiency efforts but also addresses natural gas efficiency to a limited degree. We have not attempted to address more efficient use of transportation fuels.

Efficiency Potential Studies

We reviewed seven major efficiency potential studies that have been completed in the WGA region in the past five years. The studies vary in terms of their timeframe for projecting electricity savings potential, their geographical coverage, and their approach. Some examine technical and economic savings potential only; others consider achievable savings potential from specific policies and programs. Nonetheless, the studies as a whole show that there is considerable cost-effective and achievable electricity savings potential in the western states.

In general, the efficiency potential studies show it is possible to reduce electricity demand growth by 0.5-2% per year through more concerted energy efficiency efforts. For comparison, the energy efficiency goal in the WGA clean and diversified energy resolution is equivalent to about a 1.4% annual reduction in electricity demand growth. Studies that consider a wider set of efficiency measures and more aggressive implementation strategies tend to project savings at the higher end of this range, while those with more limited measures and/or more conservative assumptions about measure adoption are at the lower end. The studies that examined potential net economic benefits all found that more aggressive, multi-year energy efficiency efforts could save consumers and businesses billions of dollars over the lifetime of the measures, with very favorable benefit-cost ratios.

Barriers to Greater Energy Efficiency

Despite the many benefits, there are a wide range of market failures or barriers that inhibit greater investment in energy efficiency measures by households and businesses, including:

- limited supply and availability of some energy efficiency measures such as newer measures manufactured on a limited scale or not yet widely marketed;
- consumers lacking or having incomplete information about energy efficiency options;
- consumers and businesses lacking the capital to invest in energy efficiency measures;
- lack of staffing or time within businesses and industries;
- fiscal or regulatory policies that discourage energy efficiency investments;
- decision making that does not consider or value energy efficiency;
- perceived risk associated with the performance of relatively new energy efficiency measures;
- split incentives whereby the party designing, constructing, or purchasing a building or piece of equipment does not pay the operating costs; and
- energy prices that do not reflect the full costs imposed on society by energy production and consumption (so-called externalities).

Taken as a whole, these barriers lead to relatively limited adoption of cost-effective energy efficiency measures in the marketplace. In order to realize the broad

benefits offered by greater energy efficiency, there is justification for adopting policies and programs to remove or overcome these barriers.

Best Practice Policies and Programs

The Task Force reviewed a wide range of energy efficiency policies and programs being implemented across the WGA region. We identified numerous efforts that we consider exemplary. These "best practice" policies and programs are briefly summarized below.

Electricity Energy Efficiency Programs

Leading utilities such as California's investor-owned utilities, Austin Energy, Puget Sound Energy, and Seattle City Light are spending at least 2% of their revenues on energy efficiency and load management programs. These programs are cutting electricity use by 0.8-1.0% per year, from efficiency measures installed each year (i.e., the programs would reduce electricity use by 8-10% from cumulative efforts over ten years). California and Texas have set energy savings targets for their electric utilities. In addition, utilities in Hawaii and Nevada may use energy savings from efficiency measures to meet at least a portion of their clean energy requirements.

Funding for these programs is typically provided through utility rates and/or tariff riders. Some states, including California, Montana, and Oregon, have created a funding mechanism via a separate surcharge known as a public benefits fund. Most of the programs are saving electricity at a total cost of 2-3 cents per kWh saved.

Building Codes and "Beyond Code" Programs

Leading states have adopted a recent version of the International Energy Conservation Code (IECC), or a customized energy code that is as least as stringent as this model code; e.g., California's Title 24 building efficiency standards. Also, leading states update their energy codes at least once every three years, and leading states train architects, builders, and local code officials in how to comply with new codes.

A number of western states and utilities implement programs to encourage construction of new homes and commercial buildings that exceed minimum energy code requirements. These programs typically provide training and technical assistance to architects, builders, and contractors as well as promotion and consumer education. In some cases, financial incentives are offered to builders or homeowners who construct/buy buildings that exceed the minimum code requirements. In the residential sector, many of these programs promote construction of ENERGY STAR® new homes.

Appliance Standards

California is leading the nation in developing and enacting minimum efficiency standards on appliances that are not regulated by the federal government. Other western

states including Arizona, Oregon, and Washington have adopted appliance efficiency standards on some of the same products regulated by California. These standards are very cost-effective with energy bill savings paying back any additional first cost in two years or less in most cases.

Research and Development (R&D) and Technology Transfer

A few western states support R&D on innovative energy-efficient technologies and/or support technology transfer. California's Public Interest Energy Research (PIER) program invests in R&D to increase the energy efficiency of electric and natural gas technologies and services in California. The Washington State University Energy Program trains industrial energy and facility managers in best practice energy management, provides technical assistance to individual companies, conducts field research and testing on issues such as indoor air quality and moisture problems in buildings, and supports implementation of the state's building energy code.

Public Sector Initiatives

Many western states have acted to cut energy waste in public buildings. Leading initiatives include:

- Legislation in Arizona that directs state agencies and universities to achieve a 10% reduction in energy use per unit of floor area by 2008 and a 15% reduction by 2011.
- In California, Governor Schwarzenegger issued an Executive Order requiring that all new and renovated state buildings achieve a LEED™ silver level certification or higher, and setting a goal for all state buildings to be 20% more efficient by 2015.
- Colorado has made considerable progress in using energy service companies (ESCOs) and performance contracting to carry out energy efficiency projects in state and local government buildings as well as in public schools.
- The Kansas Facility Conservation Improvement Program retrofitted about 50% of all state facilities over five years using a streamlined performance contracting model.
- The Texas LoanSTAR program provides low-interest loans for energy-conserving retrofits made in state, county, and local government buildings and independent school districts. The original fund has "revolved" 2.3 times and funded 182 loans for $227 million since 1989.

Tax Credits and Other Financial Incentives

There are relatively few examples of tax credits or other financial incentives for energy efficiency measures and projects in western states, apart from utility and other ratepayer-funded programs. Oregon is the exception, offering both households and businesses tax credits for investments in a wide range of energy efficiency measures.

Pricing and Regulatory Policies

At least four western states (CA, OR, UT, and WA) have adopted inverted block electricity rates (also known as tiered rates) for residential customers. This means the cost per kWh increases as electricity consumption increases, thereby encouraging energy efficiency and conservation. California and Oregon have taken regulatory action to ensure that investor-owned utilities are not penalized financially for implementing effective energy efficiency programs. Both states have adopted mechanisms to decouple utility sales and revenues. Also, California and Pacific Northwest states fully integrate energy efficiency options into utility resource planning.

Regional Cooperation and Market Transformation

The Northwest Energy Efficiency Alliance (NEEA) is increasing the supply of and demand for energy efficiency measures in Idaho, Montana, Oregon, and Washington. Projects target all sectors, striving to remove barriers to energy efficiency adoption in the marketplace. NEEA estimates its activities in 2004 reduced electricity use in the region by 420 GWh/yr, equivalent to about 0.25% of annual electricity use in the four-state region. NEEA achieves electricity savings at an average cost of about 1.0 cent per kWh (program costs only).

Energy Efficiency as an Air Pollution Control Strategy

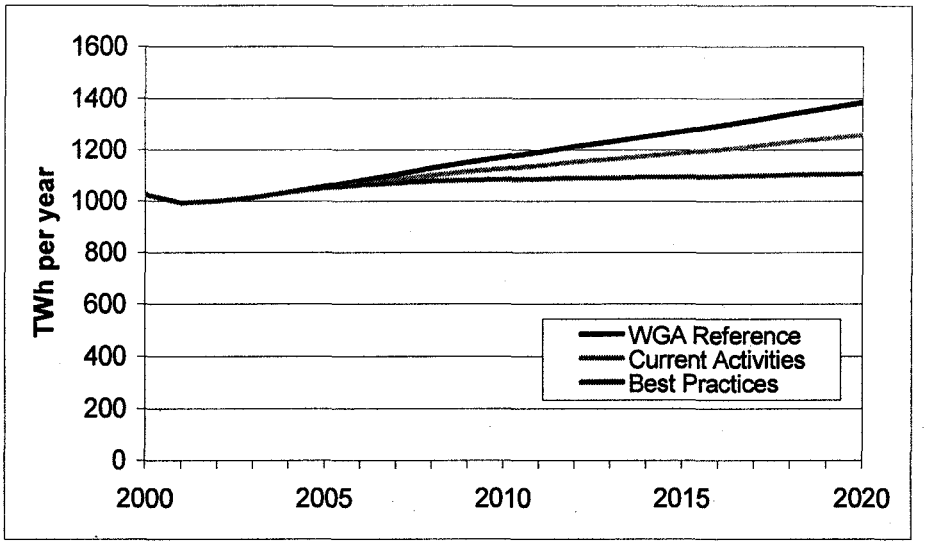
Texas is providing leadership in analyzing air emissions reductions from energy efficiency programs and incorporating energy efficiency initiatives into clean air compliance plans. Also, the Western Regional Air Partnership (WRAP) is encouraging states to include energy efficiency programs in their pollution control strategies.

Analysis of Energy Efficiency Potential

In order to assess potential electricity savings and the impacts of more aggressive energy efficiency efforts in western states, the Task Force conducted an independent energy savings analysis. With the help of a consultant, we developed and analyzed the following three scenarios for electricity demand in the 18-state region through 2020:

- **Reference scenario**: a slightly modified version of the most recent Reference Case forecast prepared by the Energy Information Administration, applied to WGA states.
- **Current Activities scenario**: adjusting the Reference scenario to account for the estimated impacts of ongoing and recently enacted policies and programs at the state, regional, or utility levels.
- **Best Practices scenario**: assuming adoption of "best practice" policies and programs, as identified in Chapter IV, in all 18 states.

Figure ES-1. Electricity Consumption in WGA states by Scenario



As shown in Figure ES-1, load growth during 2003-2020 averages 1.9% per year in the Reference scenario, 1.3% per year in the Current Activities scenario, and 0.5% per year in the Best Practices scenario. As noted above, electricity consumption increased 1.7% per year on average during 1990-2003 in the 18 WGA states. **We conclude that widespread adoption of best practice policies and programs would not eliminate all load growth over the next 15 years, but it would reduce it by about three-quarters.**

The Best Practices scenario reduces electricity consumption in 2020 by 20% relative to that in the Reference scenario, or the equivalent of electricity supplied by 100 baseload power plants. Thus we conclude it is possible to achieve the energy efficiency goal enunciated in the WGA Clean and Diversified Energy Resolution, namely realizing 20% electricity savings by 2020. Moreover, even greater electricity savings may be possible through adoption of other strategies not included in our Best Practices scenario, such as R&D, technology transfer, or pricing initiatives.

Benefits of the Best Practices Scenario

- **20% electricity savings by 2020, relative to the Reference Scenario**
- **48,000 MW of avoided power plant construction during 2005-2020**
- **Small reduction in electricity prices in the latter part of study period**
- **$53 billion in net economic benefits for consumers and businesses**
- **Substantial reduction in power plant CO_2 emissions**
- **Moderate reduction in power plant NOx emissions**
- **Approximately 1.8 trillion gallons of water savings during 2005-2020**

Implementing the Best Practice energy efficiency policies and programs would provide substantial economic benefits for households and businesses in western states. By 2020, these efforts could lower electricity bills in aggregate by $21 billion per year. The Best Practices scenario would yield $53 billion in net economic benefits during 2005-

2020 on a net present value basis, with an overall benefit-cost ratio of 2.5. The benefits result mainly from avoided fuel purchases by utilities, and avoided investment in generation, transmission, and distribution infrastructure. Furthermore, the benefits could be even greater since relatively low natural gas prices (below $5 per thousand cubic feet) were assumed in the analysis.

Implementing the Best Practice energy efficiency policies and programs would also provide air pollutant emissions reductions. Carbon dioxide (CO_2) emissions would decline the most (17% by 2020). In addition, NOx emissions by power plants would decline a moderate amount (7% by 2020) in the Best Practices scenario, relative to the Reference Scenario.

Energy efficiency best practices would result in water savings from both increased use of energy and water saving devices in homes and businesses, and less operation of steam-based power plants. We estimate that the Best Practices scenario would save 260 billion gallons of water per year by 2020 relative to the Reference scenario, equivalent to the annual water use of about 1.4 million households. Total water savings during 2005-2020 in this scenario would be approximately 1.8 trillion gallons.

Policy Recommendations

Drawing heavily from our review of best practice policies and programs, the Energy Efficiency Task Force developed numerous policy recommendations for western states. All of these recommendations would lead to greater deployment of cost-effective energy efficiency measures, thereby helping states achieve the substantial benefits described above for the Best Practices Scenario.

Electric Utility Demand-Side Management (DSM) Programs

- Encourage or require that utilities integrate energy efficiency options into resource planning and procurement decisions and pursue energy efficiency whenever it is the least cost resource option. At a minimum, electricity distribution companies in western states should dedicate at least 2% of revenues for ratepayer-funded energy efficiency programs, as long as doing so is cost effective.
- Establish minimum energy savings requirements or targets. In particular, we recommend setting a goal of saving 3-5% of projected electricity sales in 2010 through DSM programs. By 2020, we recommend setting a goal of 10-15% savings from DSM programs, as long as doing so is cost effective.
- Decouple electricity sales and revenues so that reduced electricity sales do not adversely affect utility revenues, in combination with the creation of performance incentives that reward utilities for implementing effective DSM programs.

Gas Utility Demand-Side Management (DSM) Programs

- Encourage or require gas utilities to integrate energy efficiency resources into their resource planning and procurement decisions and pursue energy efficiency whenever it is the lowest cost option.
- Establish ratepayer-funded natural gas energy efficiency programs.
- Invest at least 1.5-2% of gas utility revenues in energy efficiency programs and strive to save the equivalent of 0.5-1.0% of gas consumption per year, as long as doing so is cost effective.
- Decouple gas utility sales and revenues and create performance incentives that reward utilities for implementing effective DSM programs.

Building Energy Codes

- For states with outdated (pre-2003) energy codes, adopt the 2004 International Energy Conservation Code. Also, consider adopting innovative features of California's latest Title 24 building energy codes, such as lighting efficiency requirements in new homes.
- Update building energy codes regularly. A three-year cycle could be timed to coincide with release of the national model codes.
- In home rule states, either establish a statewide mandatory code or strongly encourage local jurisdictions to adopt and maintain state-of-the-art codes.
- Implement training and technical assistance for builders, designers, and code officials.

Appliance Efficiency Standards

- California should continue to adopt minimum efficiency standards on products not covered by the federal standards.
- Other western states should replicate efficiency standards first adopted by California, where cost effective.

Public Sector Initiatives

- Establish substantial energy savings goals or requirements for state and municipal agencies, and track progress towards meeting them. We suggest at least a 2% annual reduction in energy use per square foot of floor area.
- Provide financial and technical assistance for implementation of energy savings projects in existing buildings and facilities.
- Use energy service companies (ESCOs) and performance contracting to implement efficiency projects without public sector capital investment.
- Construct new buildings that are exemplary and surpass minimum energy code requirements by a wide margin.
- Purchase only ENERGY STAR-labeled equipment in categories where such products are designated.

Financial Incentives

- Consider providing income or property tax incentives to help stimulate greater adoption of energy efficiency measures, and consider coordinating qualification levels with the newly adopted federal energy efficiency tax credits.
- For states with growing severance tax revenues on fossil fuels production, consider using a portion of these revenues to offset the revenue loss from tax incentives on energy efficiency measures.

Pricing Policies

- Adopt inverted block rates (also known as tiered rates) for electricity consumed by residential customers.
- Consider adopting inverted block rates for natural gas.

Education and Training

- Partner with the U.S. EPA and DOE in promoting ENERGY STAR products, homes, commercial buildings, and industries.
- Implement programs to train builders and contractors on proper heating and air conditioning sizing and installation.
- Train commercial building energy managers, for example by making use of the building operator training and certification program developed in the Pacific Northwest.
- Train industrial energy and facility managers in techniques for improving the efficiency of their steam, process heat, pumping, compressed air, motors, and other systems, partnering with the U.S. DOE in doing so.
- Educate consumers about innovative energy efficiency measures such as modern evaporative cooling systems, reflective roofing materials, sealing thermal distribution systems, and use of day lighting.
- Undertake K-12 school- and college-based energy education programs.

Technology R&D and Transfer

- Support energy efficiency R&D and technology transfer efforts through either intrastate programs or working collaboratively among states.
- Initiate, continue, and where appropriate expand programs promoting best practices in industrial energy management.
- Encourage companies to set goals for energy efficiency improvement and energy savings, and track their progress towards the goals.

Regional-Level Initiatives

- Create additional regional market transformation organizations modeled on the successful Northwest Energy Efficiency Alliance.

- Form a regional building energy code collaborative to support code development, adoption, and implementation.
- Advocate, as a region, for stronger federal appliance efficiency standards where this is technically feasible and economically justified.
- Create or utilize a regional working group to quantify the air emissions benefits of energy efficiency programs and foster inclusion of energy efficiency initiatives in state and regional air quality improvement plans.
- Ensure that the potential for and effects of energy efficiency efforts are incorporated in regional transmission planning.
- Encourage Native American tribes to work together in hiring and training energy managers and contractors.
- Reduce barriers to performance contracting and implement other strategies for increasing energy efficiency in commercial buildings.

Conclusion

Increasing energy efficiency should be a major component of energy strategies developed and implemented by Western Governors. Some western states have already undertaken important initiatives including adopting comprehensive and well-funded utility energy efficiency programs, up-to-date building energy codes and/or appliance efficiency standards, initiatives to improve energy efficiency in the public sector, tax credits, and R&D and technology transfer efforts. In addition, the Pacific Northwest states have formed a model organization aimed at transforming energy efficiency markets at the regional level. But much more can and should be done.

Adopting "best practice" energy efficiency policies and programs in all western states could eliminate most of projected load growth during 2005-2020, reduce overall electricity consumption in 2020 by 20% relative to a scenario without energy efficiency initiatives, and yield tremendous economic and environmental benefits.

In order to realize these broad benefits, we recommend that Western Governors work with their legislatures, state regulatory commissions, and private sectors to enact new policies aimed at increasing the efficiency of both electricity and natural gas use. There is no "silver bullet" for overcoming the barriers that are inhibiting widespread energy efficiency improvements. But there are a variety of proven policies and programs that are available for states to take advantage of. With energy costs high and rising, the time to act is now.

I. Introduction

The western U.S. contains the fastest growing states in the country in terms of population and energy consumption.[3] Table I-1 shows retail electricity sales in each of the 18 WGA states during 1990-2003. For the region as a whole, electricity sales increased 1.7% per year on average during this period. But electricity use in Nevada climbed nearly 5% per year and electricity use in Arizona, Colorado, North Dakota, and Utah increased more than 3% per year on average during 1990-2003. Rapid growth in electricity demand presents a number of challenges for the region including high investment requirements in new generation, transmission and distribution facilities, increasing risk of power shortages, increasing water consumption, and more harmful emissions by power plants.

Table I-1. Retail Electricity Sales in WGA States, 1990-2003

	Retail Electricity Sales (TWh/yr)			Average growth 1990-2003 (%/yr)
State	1990	2000	2003	
Alaska	4.3	5.3	5.6	2.1
Arizona	41.5	61.1	64.1	3.4
California	211.1	244.1	237.9	0.9
Colorado	30.8	43.0	46.5	3.2
Hawaii	8.3	9.7	10.4	1.8
Idaho	18.0	22.8	21.2	1.3
Kansas	27.1	35.9	36.7	2.4
Montana	13.1	14.6	12.7	-0.2
Nebraska	17.9	24.3	25.9	2.9
Nevada	16.4	27.8	30.1	4.8
New Mexico	13.8	18.8	19.3	2.6
North Dakota	7.0	9.4	10.5	3.2
Oregon	43.0	50.3	45.2	0.4
South Dakota	6.3	8.3	9.1	2.9
Texas	237.4	318.3	322.6	2.4
Utah	15.4	23.2	23.8	3.4
Washington	91.0	96.5	78.1	-1.2
Wyoming	11.8	12.4	13.3	0.9
TOTAL	**814.2**	**1,025.8**	**1,012.9**	**1.7**

Source: Energy Information Administration, U.S. Department of Energy.

California and nearby states were severely impacted by the western electricity crisis in 2000-2001. Electricity sales in Montana, Oregon, and Washington fell significantly between 2000 and 2003 due primarily to contraction by electricity-intensive industries (NPPC 2005). As shown in Table I-1, total electricity sales in all WGA states

[3] The five fastest growing states in the nation during 1990-2000 were Nevada, Arizona, Colorado, Utah, and Idaho.

actually declined slightly between 2000 and 2003. Some of the decline was due to electricity efficiency and conservation efforts, particularly during the 2001 electricity crisis.

Energy prices have risen significantly in western states in recent years. The average electricity price in a number of WGA states including Colorado, Oregon, and Texas increased more than 20% between 2000 and the first half of 2005. Natural gas prices have risen even more dramatically. Most households in the WGA region were paying at least $12 per thousand cubic feet for gas in mid-2005, approximately twice as much as they were paying for gas in 2000. Natural gas prices rose further in the wake of hurricanes Katrina and Rita in September, 2005. High and volatile natural gas prices are affecting electricity prices and are expected to persist for a number of years.[4]

The pattern of electricity usage in many western states is also of concern. Summer peak electricity demand, driven by use of air conditioning, is rising faster than overall electricity use. This reduces the utility system load factor (the ratio of average-to-peak power demand), meaning utilities are not making good use of their power supply infrastructure. This in turn contributes to rising electricity prices.

Increasing the efficiency of energy use in western states will help to address all of these challenges and will provide a broad range of benefits, including:

- saving consumers and businesses money on their energy bills;
- reducing dependence on imported fuel sources;
- reducing vulnerability to energy price spikes;
- reducing peak demand and improving the utilization of the electricity system;
- reducing the risk of power shortages;
- supporting local businesses and stimulating economic development;
- enabling avoidance of the most controversial energy supply projects;
- reducing water consumption by power plants; and
- reducing pollutant emissions by power plants and improving public health.

In short, increasing energy efficiency is a "win-win strategy" for consumers, businesses, utilities, and the environment in western states.

Some western states have taken significant steps to increase the efficiency of energy use in recent years. These include expanding electric utility demand-side management (DSM) programs, upgrading building energy codes, adopting appliance efficiency standards, encouraging construction of ENERGY STAR® new homes and purchase of ENERGY STAR products, and taking action to cut energy waste by the public sector. These and other "best practice" energy efficiency initiatives are reviewed in Chapter IV of this report.

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[4] These energy prices are taken from various U.S. Energy Information Administration data bases and reports, www.eia.doe.gov.

Chapter V of the report presents our analysis of electricity savings potential in the WGA region. We develop and analyze the impacts of current policies and programs that are advancing more efficient electricity use, as well as the potential energy, economic, and environmental benefits of full adoption of "best practice" policies and programs throughout the WGA states. This analysis addresses the feasibility of the WGA energy efficiency goal, namely that "**Western Governors will examine the feasibility of and actions that would be needed to...increase the efficiency of energy use by 20% by 2020. While energy efficiency does not eliminate the need for new generation, it is critical that western states pursue an energy efficient system.**"[5]

Before considering state-of-the art energy efficiency policies and programs, we review other recent studies of energy efficiency potential, specifically electricity conservation potential, in one or more western states (Chapter II). These studies support our own analysis showing very substantial cost-effective electricity savings potential.

In Chapter III, we briefly review the market failures and barriers that inhibit more widespread adoption of cost-effective energy efficiency measures. There are numerous barriers that taken together lead to significant underinvestment in energy efficiency. The existence of these barriers provides justification for policies and programs to overcome them and stimulate greater investment in energy efficiency by households and businesses.

Much more can be done and in our view should be done to increase energy efficiency in western states. Chapter VI presents our policy recommendations. The recommendations are directed to state policymakers but include suggestions for regional initiatives as well as state-level actions. By adopting these policy recommendations, western states can achieve the energy efficiency goal in WGA's 2004 clean and diversified energy resolution.

[5] This goal was included in the Clean and Diversified Energy Resolution adopted by the Western Governors' Association in June, 2004. http://www.westgov.org/wga/policy/04/clean-energy.pdf.

II. Review of Energy Efficiency Potential Studies

A. Introduction

During the mid-1990's, many electric utility energy efficiency programs were viewed as extraneous operations and were cut during the restructuring and deregulation wave. By 2000, there was renewed interest in and funding for utility energy efficiency programs due to concerns about system reliability, price volatility, supply shortages, and other factors (York and Kushler 2002). This was especially the case in western states affected by the 2001 electricity supply crisis. Many states, utilities, and energy efficiency advocates prepared energy efficiency potential studies, taking into account current market conditions and newly commercialized efficiency measures.

This chapter reviews seven major efficiency potential studies that have been completed in WGA member states in that past five years. Many of the studies concentrate on opportunities in individual states, while several illustrate regional energy potential prospects. The studies that were examined and their date of publication are as follows:

- Utah Public Service Commission DSM Report (2001)
- WRAP: Renewable Energy and Energy Efficiency as Pollution Prevention Strategies for Regional Haze Reduction (2001)
- The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest (2002)
- Califonia's Secret Energy Surplus: The Potential for Energy Efficiency (2002)
- Energy Trust of Oregon Efficiency Potential Study (2003)
- Northwest Power and Conservation Council's Fifth Plan (2005)
- Puget Sound Energy: Assessment of Technical and Achievable Demand-Side Resource Potentials (2005)

The seven energy efficiency potential studies reviewed here help to guide the assumptions, scenarios, and data sources chosen by the Western Governors' Association Energy Efficiency Task Force in their modeling efforts. The Western Governors' Association has previously examined energy efficiency potential in Mexico along the region that borders several WGA member states (WGA 2004). The Energy Efficiency Task Force has been charged with a similar analysis for the WGA region.

The scope of analysis for the studies varies as does the timeframe for projections. The general range for forecasting electricity savings potential tends to be from 10 to 20 years. The studies mainly concentrate on the electric potential in the residential, commercial, and industrial sectors. While these three sectors represent the main area of focus, several studies incorporate a sector that is classified as "other." As mentioned previously, we only include efficiency potential studies that cover some portion of the WGA region.

B. Comparison of Potential Studies

Tables II-1, II-2, and II-3 show key data from each of the seven studies in consistent units. For each study, when the information was presented, we show the maximum peak savings in Megawatts (MW) by the end of the study period, maximum net electricity savings in Gigawatt-hours per year (GWh/yr) by the end of the study period, and the net economic benefit in year 2000 dollars. All data are for the most aggressive efficiency scenario in each study. These figures help to illustrate the potential savings that energy efficiency programs and measures could provide in western states.

Table II-1. Energy Savings Identified by Potential Studies

	Net Energy Savings (GWh/yr)						
	Utah	WRAP	SWEEP	Oregon	NPCC	California	PSE
Study Length (years)	6	15	17	10	20	10	20
Residential	191	89,646	24,593	3,570	7,562	9,400	1,169
Commercial	N/A	171,924	50,291	3,190	5,843	12,000	1,293
Industrial	N/A	3,223	24,150	2,680	8,254	8,700	139
Total	2,309	264,793	99,034	9,440	21,900	30,100	2,601

Table II-2. Maximum Peak Savings Identified by Potential Studies

	Maximum Peak Savings (MW)						
	Utah	WRAP	SWEEP	Oregon	NPCC	California	PSE
Residential	186	N/A	N/A	N/A	N/A	1,800	N/A
Commercial	N/A	N/A	N/A	N/A	N/A	2,550	N/A
Industrial	N/A	N/A	N/A	N/A	N/A	1,550	N/A
Total	682	N/A	N/A	N/A	N/A	5,900	N/A

Table II-3. Cumulative Economic Savings Identified by Potential Studies

	Net Savings ($million)						
	Utah	WRAP	SWEEP	Oregon	NPCC	California	PSE
Study Length (years)	25 (1)	15	17	10	20	10	20
Residential	272	N/A	6,100	N/A	N/A	N/A	
Commercial	614	N/A	14,700	N/A	N/A	N/A	N/A
Industrial	187	N/A	7,500	N/A	N/A	N/A	N/A
Total	1,073	N/A	28,200	N/A	2,000	11,900	N/A

(1) The Utah study considered efficiency measure implementation over a six year period but economic costs and benefits over 25 years.

Besides the obvious energy and cost saving benefits, some of the studies estimate the potential air emissions and water usage reductions, and externalities that include job creation and wage increases. These topics are beyond the scope of this comparison, but are discussed in more detail in the summaries of the various studies.

Table II-4 compares the overall energy savings potential identified in these studies, where available. These figures represent the percentage of load that is compensated for by the adoption of the energy efficiency measures at the end of the study period, for the most aggressive scenario in each study.

The studies vary considerably in terms of savings potential. This is due to factors such as the number and type of efficiency measures considered and assumptions about policies, programs, and adoption rates. For example, the California and Utah studies consider savings potential achievable through expanded utility DSM programs only, while the SWEEP study considers savings potential from a broader set of policies and programs including DSM programs, building codes, and appliance efficiency standards.

In general the studies indicate achievable energy savings potential of 0.5-2% per year. The Energy Trust of Oregon study, showing savings potential of about 3% per year, represents the full technical and economic savings potential, not an estimate of achievable potential. For comparison, the energy efficiency goal in the WGA clean and diversified energy resolution is equivalent to about a 1.4% annual reduction in electricity demand growth.

Table II-4. Maximum Energy Savings Potential Identified by Study

Study	Study Period (years)	Savings Potential (%)
Utah DSM Potential	6	9
California Secret Surplus	10	10
Energy Trust of Oregon	10	31
Puget Sound Energy	20	10
SWEEP	18	33
Northwest Power Plan	20	10

C. Summary of Individual Studies

1. Utah Public Service Commission DSM Report (2001)

Overview

This study was prepared by the Tellus Institute for the Systems Benefit Charge Stakeholder Advisory Group to the Utah Public Service Commission (Nichols and Von Hippel 2001). It contains a detailed forecast of the energy and economic effects that new demand-side management (DSM) measures implemented during 2001-2006 could have in the state of Utah. The report examines cost-effective and achievable energy efficiency potential. It covers the effects of past DSM programs, market trends, and existing policy as a baseline for the analysis of proposed future measures that include load management,

energy efficiency, and combined heat and power.[6] These three categories serve as general headings for a more comprehensive portfolio that included the following:

Residential Measures
- Air conditioner load control
- Efficient cooling equipment
- Residential lighting
- Appliance recycling

Commercial Measures
- Air conditioner load control
- Load management
- Efficient cooling equipment/systems
- Commercial lighting
- Efficient refrigeration
- Combined heat and power (CHP)

Industrial Measures
- Load management
- Efficient motors
- Motor drive improvements
- Combined Heat and Power (CHP)

The scenario described above was modeled through 2025, but with measure adoption limited to 2001-2006.[7] Energy savings continue over the life of efficiency measures, and end by 2025. Results indicate annual energy savings that reach a maximum of 2,300 GWh/yr and a peak demand reduction of 680 MW per year by 2006. The entire DSM portfolio provides a cumulative energy savings of 40,700 GWh during 2001-2025. The results by sector are summarized in Table II-5 (note that the commercial and industrial sectors were analyzed together).

Table II-5. Energy Savings and Net Economic Benefits in the Utah DSM Study

	Commercial	Industrial	Residential	Total
Net Energy Savings in 2006 (GWh/yr)	N/A	N/A	191	2,309
Peak Demand Reduction in 2006 (MW)	N/A	N/A	186	682
Net Benefits (million $)	614	187	272	1,073

Economic Impact

The Utah DSM study estimated that the high efficiency scenario would yield $1.44 billion in gross economic benefits and $1.07 billion in net economic benefits. The costs of efficiency measures include estimated DSM program costs as well as measure

[6] The study was not exhaustive in the analysis of potential DSM programs and knowingly omitted non-residential new construction practices and industry-specific efficiency standards.

[7] It is noteworthy that a five-year adoption period is unusual in energy efficiency potential studies and was modeled in this particular study at the request of the utility.

costs. The overall benefit-cost ratio came out to be 3.9 while individual measures in the DSM portfolio had benefit-cost ratios ranging from 2.3 to 10.0. The study also notes a "net plus" in the relationship between DSM programs and local employment; however, the impact is classified as relatively small and is not quantified.

Environmental Impact

In the context of this study, emissions, land, and water use were also described as externalities to the adoption of the DSM portfolio and were left out of any economic calculations. However, it is estimated that the High Efficiency scenario would provide the following air emissions reductions from 2001 to 2025:

- 14,600 tons of NO_x
- 16 million tons of CO_2

Outcomes

This study helped pave the way for development and approval of DSM programs by PacifiCorp (Utah Power), the main electric utility operating in Utah. PacifiCorp has been steadily increasing its funding for energy efficiency programs since 2001, with encouragement from the state and other stakeholders (see Chapter IV for more details).

2. WRAP Air Pollution Prevention (AP2) Forum: Renewable Energy and Energy Efficiency as Pollution Prevention Strategies for Regional Haze Reduction (2002)

Overview

In its 1996 report to Congress, the Grand Canyon Visibility Transport Commission (GCVTC) concluded that renewable energy and energy efficiency measures could result in "emissions reductions, improvements in visibility, and provide secondary environmental and economic benefits to the region." The Western Regional Air Partnership (WRAP) was established by western states and tribes to coordinate and oversee implementation of the GCVTC recommendations on energy efficiency and renewable energy and provide policy and technical tools to assist states and tribes in filing regional haze implementation plans.

The WRAP in turn created an Air Pollution Prevention Forum to develop and analyze policies and programs that states and tribes could adopt. The Air Pollution Prevention Forum commissioned a study by the ICF Consulting Group and Tellus Institute (2002) examining the emissions, costs, and regional economic impacts of different energy efficiency and renewable energy scenarios. Separate models were used to analyze electricity sector and macroeconomic impacts. The study considered a business-as-usual (BAU) scenario and three alternative scenarios related to the WRAP's 10/20 goals.[8] The three scenarios regarding energy efficiency and renewable energy implementation are as follows:

[8] The 10/20 goals call for renewable energy to account for 10% of regional power requirements by 2005 and 20% by 2015.

- The 10/20 goals
- New energy efficiency measures (EE)
- The 10/20 goals + EE

The energy efficiency assumptions were developed by the Tellus Institute. Electricity savings start at 1% of total electricity use in the WRAP states in 2005 and grow to 8% saving by 2018. Table II-6 shows the cumulative savings in 2018 by sector.

Table II-6. Energy Savings and Net Economic Benefits from Energy Efficiency in the WRAP Study

	Residential	Commercial	Industrial	Total
Net Energy Savings (GWh)	89,646	171,924	32,223	293,793
Net Benefits (million $)				15,000

Economic Impacts

According to this study, the energy efficiency measures result in a very slight reduction in wholesale electricity prices across the region. The levelized annual cost of supplying electricity falls by about $1 billion (6%), resulting in about $15 billion in net savings over the 18-year study period. This estimate includes the cost of energy efficiency implementation. Furthermore, the economic benefits from energy efficiency more than offset the incremental costs of renewable energy adoption in order to meet the 10/20 goals, in the combined energy efficiency and renewable energy scenario.

Environmental Impact

Emissions forecasts were estimated for the 10/20+EE scenario in comparison to the BAU scenario. The report indicates that the 10/20+EE scenario would reduce NO_X emissions by 14,000 tons and CO_2 emissions by 55 million metric tons annually by 2018 relative to the BAU scenario.

Outcomes

This study was used by five states (AZ, NM, OR, UT, and WY) to fulfill legislative requirements related to energy efficiency and renewable energy in their state implementation plans (SIPs) in response to EPA's regional haze rule. It was also used in testimony before the Utah Public Service Commission in support of increased funding for utility energy efficiency programs.

3. The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest (2002)

Overview

The Southwest Energy Efficiency Project (SWEEP) completed a study in 2002 that examines the potential for more efficient electricity use in Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming, along with an analysis of the potential economic and environmental benefits of a high-efficiency future in this region (SWEEP 2002). The study develops two scenarios, a business-as-usual (BAU) scenario that

assumes current policies and trends are maintained, and a high efficiency scenario. The high efficiency scenario assumes widespread adoption of cost-effective energy efficiency measures during 2003-2020.

The BAU scenario in this study projects electricity demand will grow 2.6% per year on average during 2003-2020. In the high efficiency scenario, demand grows 0.4% per year during 2003-2020, meaning total electricity use in 2020 is reduced by 33% compared to the BAU scenario. Table II-7 presents the electricity savings in 2020 and the average cost of saved energy in the high efficiency scenario by sector. The electricity savings result from efficiency measures that are implemented over an 18-year period.

Table II-7. Energy Savings and Net Economic Benefits from Energy Efficiency by 2020 in the SWEEP Study

	Residential	Commercial	Industrial	Total
Energy Savings (GWh)	24,600	50,300	24,150	99,050
Cost of Saved Energy (cents/kWh)	2.9	1.4	2.1	2.0

Economic Impacts

With an average cost of $0.02 per kWh saved, the high efficiency scenario in the SWEEP study results in large economic benefits for consumers and businesses in the Southwest. SWEEP estimates the scenario would provide $37 billion in gross economic benefits and $28 billion in net economic benefits, with an overall benefit-cost ratio of 4.2. The SWEEP study also analyzed the macroeconomic implications of pursuing the high efficiency scenario, which would lead to an estimated net increase of 58,000 jobs by 2020 (a 0.45% increase in the regional employment rate).

Environmental Impacts

The SWEEP study estimated the reductions in SO_2, NO_X, carbon dioxide, and mercury emissions that would result from the reduced electricity consumption in the high efficiency scenario, relative to the BAU scenario. These estimates are summarized in Table II-8. Carbon dioxide emissions are reduced the most since these pollutants are not otherwise controlled. There are smaller reductions in the other pollutants in percentage terms because they are subject to regulations and/or controls, and the avoided new power plants in the high efficiency scenario are relatively clean compared to older power plants.

Table II-8. Environmental Benefits in the SWEEP Study

	Emissions Reduction (%)	
	2010	2020
Carbon dioxide	13	26
SO_2	1	4
NO_X	2	5
Mercury	3	7

Additionally, SWEEP estimates that the high efficiency scenario would reduce water consumption in 2010 and 2020 by 24.7 and 61.6 billion gallons per year, respectively.

Outcomes

The SWEEP study was presented to policy makers and used to support energy efficiency advocacy efforts throughout the Southwest. It helped to increase funding for utility energy efficiency programs in the six states from just $21 million in 2001 to approximately $75 million in 2005 (Geller 2004). It also influenced other actions such as updating of state or local building energy codes and new initiatives to increase energy efficiency in the public sector.

4. California's Secret Energy Surplus: The Potential for Energy Efficiency (2002)

Overview

The California Secret Energy Surplus Study was published with the intention of highlighting additional and long-term energy efficiency potentials. The study, performed by Xenergy, Inc. (Rufo and Coito 2002) for the Hewlett Foundation, builds off of two previous studies performed by the California Energy Commission (CEC) and several major California utilities. Analysis extends across the residential, commercial, and industrial sectors to provide an outlook of technical, economic, and achievable energy savings potential over the ten year period of 2002-2011.

Three scenarios were developed to predict how future DSM funding levels would affect electricity savings. A business-as-usual scenario serves as the baseline. In this scenario, it is assumed that DSM program funding statewide remains steady at the average level of the late-1990s, $240 million per year. The Advanced and Maximum Efficiency scenarios were then developed assuming that this level of funding would be approximately doubled or quadrupled, respectively. Additionally, the efficiency scenarios were simultaneously run at three levels (low, base, and high) of energy costs to take into account uncertainty in future energy prices. Table II-9 shows the results in the Maximum Efficiency Scenario assuming base energy costs.

Table II-9. Energy Savings and Net Economic Benefits by 2011 from the Maximum Efficiency Scenario in the California Study

	Residential	Commercial	Industrial	Total
Peak Demand Savings (MW)	1,800	2,550	1,550	5,900
Net Energy Savings (GWh)	9,400	12,000	8,700	30,100
Net Benefits (million $)	N/A	N/A	N/A	11,900
Benefit-cost ratio	N/A	N/A	N/A	2.05

Economic Impacts

The Secret Surplus report helped to reveal the benefits that can still be reaped by adopting further energy efficiency measures in California, a state that has aggressively pursued energy efficiency over the past 30 years. Table II-10 illustrates the magnitude of the potential energy and economic benefits by scenario, given the base case energy cost assumptions. The benefit-cost ratio declines only slightly in moving from the BAU to the Maximum Efficiency scenario, demonstrating that there is still very substantial cost-

effective electricity savings potential even in a state that has implemented relatively aggressive energy efficiency efforts over the past 30 years.

Table II-10. Cumulative Benefits from the California Efficiency Potential Study, 2002-2011

	Funding Level		
	BAU	Advanced	Maximum
Peak Demand Savings (MW)	1,800	3,500	5,900
Net Energy Savings (GWh)	9,400	19,450	30,100
Net Benefits (million $)	5,550	8,600	11,900
Benefit-cost ratio	2.37	2.18	2.05

Environmental Impacts

The study makes no specific mention of the environmental impacts of the energy efficiency measures.

Outcomes

The Secret Energy Surplus study was instrumental in expanding the budget and goals for utility sponsored DSM programs in California. In 2004, the California PUC adopted new 10-year goals for utility energy efficiency programs to be implemented through 2013. The goals are 23,200 GWh/yr of electricity savings and 4,900 MW of peak demand reduction from a ten-year effort (CPUC 2004). These goals are midway between the savings potential identified in the Advanced and Maximum Efficiency scenarios in the Secret Energy Surplus study.

5. Energy Trust of Oregon (2003)

Overview

The Energy Trust of Oregon (ETO) is a statewide entity now implementing energy efficiency programs on behalf of gas and electric utilities in Oregon. At its outset, the Energy Trust of Oregon commissioned an energy efficiency potential study by a team of consultants from Ecotope, Inc., the American Council for an Energy-Efficient Economy, and the Tellus Institute (2003). The objective was to identify and analyze a wide range of energy efficiency measures in the service areas of PacifiCorp and Portland General Electric. The analysis was performed with the assumption that all cost-effective efficiency measures would be fully adopted over a ten-year period; i.e., it is a technical and economic potential study. No attempt was made to estimate the achievable savings potential from specific policies or programs.

Table II-11 presents the energy savings potential estimates over a ten-year period. The total savings potential after the ten-year effort is equivalent to 31% of projected electricity sales in the final year. It is important to note that these energy savings figures are based on a cost-effective threshold of $0.05 per kWh saved. This indicates that greater energy savings are possible, but at a less attractive benefit-cost ratio.

Table II-11. Energy Savings Projections in the Energy Trust of Oregon Study

	Residential	Commercial	Industrial	Total
Energy Savings (GWh/yr)	3,570	3,190	2,680	9,440
Savings as Fraction of Sales (%)	27.8	32.2	35.1	31.1

Economic Impact
The Oregon study did not present specific economic benefits.

Environmental Impact
The study makes no specific mention of the environmental impacts of the energy efficiency measures.

Outcomes
The study helped to justify the funding that was approved for the Energy Trust of Oregon as well as provide direction for initial program and efficiency measures selection. The savings potential study will be updated in 2006.

6. Puget Sound Energy: Assessment of Technical and Achievable Demand-Side Resource Potentials (2005)

Overview

Puget Sound Energy (PSE) is Washington's largest utility serving nearly one million electric customers in the Puget Sound region. PSE recently sponsored a study examining the potential for energy efficiency measures, fuel conversion options, and demand response strategies (Haeri, Seiden, and Perussi 2005). The study developed consistent "bundles" of measures that would allow for a comparison between both existing and proposed demand-side options. Overall, 127 measures were considered. The study examined both technical and achievable potentials, with the latter being more conservative. Cost effectiveness was used to determine if measures are feasible. Table II-12 shows the savings potential from electric energy efficiency measures in 2025 for the achievable potential scenario. The total savings represent 9.5% of the electric load that is forecasted for 2025 without expanded efficiency efforts.

Table II-12. Energy Savings Projections in the Puget Sound Energy Study

	Residential	Commercial	Industrial	Total
Energy Savings (GWh/yr)	1,169	1,293	139	2,601
Achievable savings potential (%)	9.2	9.4	10.0	9.5

Economic Impacts

Efficiency measures were screened with a cost-effectiveness threshold of a levelized per-unit cost of less than $0.115 per kWh saved. The report did not estimate the potential net economic benefit from implementing the high efficiency scenarios. However, the cost estimates for the savings measures were compared directly to a

portfolio of supply alternatives in an integrated resource analysis for PSE's 2005 Least Cost Plan.

Environmental Impacts

The PSE study makes no mention of the environmental impacts of the proposed efficiency measures.

Outcomes

This study was a key input to PSE's 2005 Least Cost Plan. One of the primary conclusions of the Plan was that approximately 75% of the achievable energy efficiency and fuel conversion potential was less costly that supply-side alternatives. These results guided the establishment of program savings goals and budgets for 2006 and 2007. PSE has significantly ramped up its energy efficiency programs after integrated resource planning was begun in 2003.

7. Northwest Power and Conservation Council: Regional Electric Power and Conservation Plan (2005)

Overview

The Northwest Power and Conservation Council (NPCC) adopted its Fifth Northwest Electric Power and Conservation Plan in December of 2004 with final publication in 2005 (NPCC 2005). The Plan analyzes options to ensure the adequacy of future electricity supply in the Pacific Northwest, in the context of rising natural gas prices, uncertainty about future hydroelectric generation, and growing concerns about global warming. This is not an "energy efficiency potential study" *per se*, but it does contain a thorough examination of achievable energy efficiency potential over the long term at a regional level.

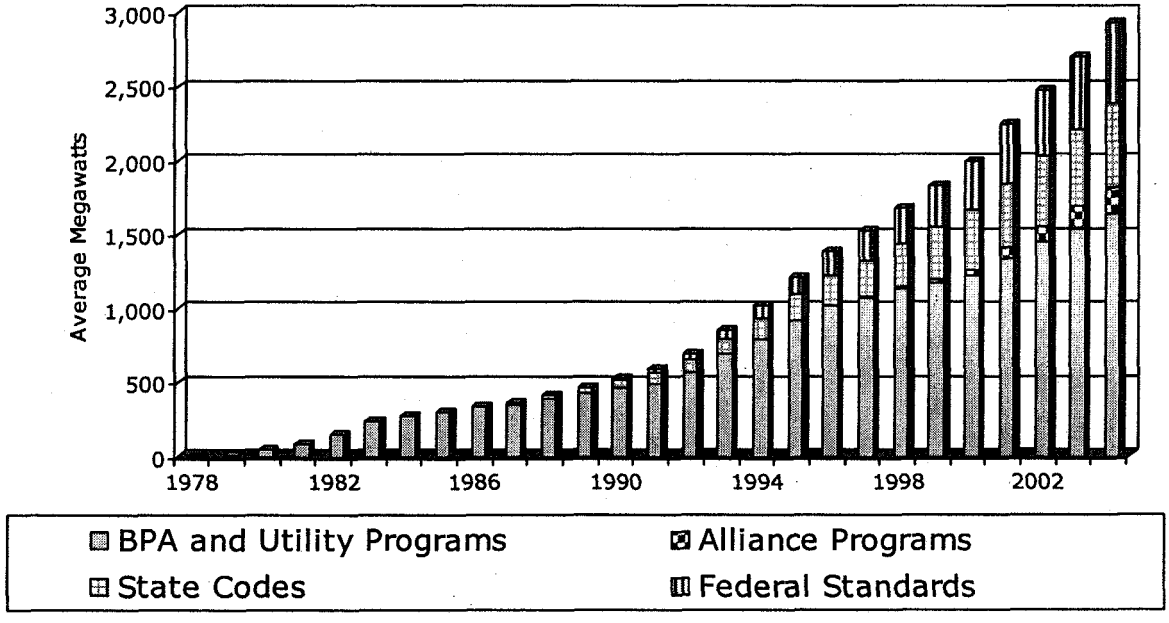
The Plan recommends that the region increase and sustain its efforts to secure cost-effective energy efficiency resources. In particular, the Plan recommends acquisition of 6,130 GWh/yr (700 MWavg) of electricity savings during 2005-2009, and a total of 21,900 GWh/yr (2,500 MWavg) of savings by the end of the 20-year planning period.[9] This is approximately 10% of projected electricity consumption in the region at the end of the planning period.

For comparison, the Northwest region developed nearly 3,000 MWavg of savings from conservation efforts implemented during 1978-2004 (see Figure II-1). About two-thirds of this historical energy savings resulted from utility DSM programs; the remainder came primarily from codes and standards. Savings were obtained at an average of $0.025 per kWh saved historically. Looking forward, the new Power and Conservation Plan anticipates that future savings will be acquired at an average cost of $0.024 per kWh, meaning that the region is not running out of cost-effective energy savings opportunities. Much of the estimated savings comes from new measures not included in previous plans

[9] Energy planners in the Pacific Northwest use the unit MWavg to represent energy consumption. One MWavg is equivalent to 8.76 GWh/yr of electricity use.

or deeper penetration of existing technologies as a result of improvements in their cost and/or performance (e.g. compact fluorescent lamps).

Figure II-1 – Electricity Savings Achieved in the Pacific Northwest, 1978-2004



Source: Northwest Power and Conservation Council.

Table II-13 lists some of the primary energy efficiency measures included in the analysis supporting the conservation goals in the new Northwest Electric Power and Conservation Plan. Many of the measures have a cost of saved energy of less than $0.03 per kWh. In order to achieve these energy savings goals, it is estimated that utilities in the region would need to spend about $250 million per year on conservation programs during the first five years of Plan implementation. In addition, the Plan recommends adopting improved building energy codes and appliance efficiency standards, expanding regional coordination and market transformation efforts, removal of other barriers inhibiting vigorous conservation efforts, and better energy conservation tracking and reporting.

Economic Impacts

The Fifth Northwest Electric Power and Conservation Plan estimates that achieving the energy conservation goals will provide consumers and businesses in the region a cumulative savings of nearly $2 billion. In addition, achieving the conservation goals reduces the region's exposure to risks such as high market prices and fuel price volatility, which in turn provides additional economic value.

Table II-13. Major Energy Efficiency Measures in the 2005 Northwest Electric Power and Conservation Plan

Sector/measure	Savings Potential by 2025 (MWavg)	Cost of Saved Energy (cents/kWh)	Benefit-Cost Ratio
Res - compact fluorescent lamps	530	1.7	2.3
Res – heat pump water heaters	200	4.3	1.1
Res – clothes washers	140	5.2	2.6
Res – existing building shell	95	2.6	1.9
Res – water heaters	80	2.2	2.3
Comm – new lighting	221	1.3	8.6
Comm – new HVAC	140	3	1.5
Comm – retrofit HVAC	119	2.4	1.9
Comm – retrofit lighting	117	3.4	1.3
Comm – retrofit equipment	114	1.8	2.2
Ind – non-aluminum processes	350	1.7	2
Ag - irrigation	80	1.6	3.2
Multi – AC/DC power converters	155	1.5	2.7

Environmental Impacts

The Fifth Northwest Electric Power and Conservation Plan does not analyze the environmental impacts of the proposed energy conservation goals.

Outcomes

The Fifth Northwest Electric Power and Conservation Plan was issued in May, 2005 and therefore had not yet influenced energy efficiency efforts in the region as of October, 2005. Previous regional plans were very influential, leading to the initiation of energy efficiency programs by the Bonneville Power Administration and other utilities in the region. Previous plans also contributed to the adoption of improved building energy codes and energy efficiency standards throughout the region.

III. Market Failures and Barriers Inhibiting Greater Investment in Energy Efficiency

A. Introduction

Energy efficiency proponents point to a wide range of market failures or barriers that inhibit greater investment in energy efficiency measures, including:

- limited supply and availability of some energy efficiency measures such as newer measures manufactured on a limited scale or not yet widely marketed;
- consumers lacking or having incomplete information about energy efficiency options;
- consumers and businesses lacking the capital to invest in energy efficiency measures;
- lack of staffing and time within businesses and industries;
- fiscal or regulatory policies that discourage energy efficiency investments;
- decision making that does not consider or value energy efficiency;
- perceived risk associated with the performance of relatively new energy efficiency measures;
- split incentives whereby the party designing, constructing or purchasing a building or piece of equipment does not pay the operating costs; and
- energy prices that do not reflect the full costs imposed on society by energy production and consumption (so-called externalities).[10]

It is important to recognize there is no single market for energy efficiency. The energy efficiency "market" consists of hundreds of end uses, thousands of intermediaries, and millions of consumers (Golove and Eto 1996). In addition, it is useful to distinguish between what are generally viewed as market failures and market barriers, as indicated in Table III-1. Market failures occur if there is a flaw in the way markets operate. Market barriers are not flaws in the way markets operate, but limit the adoption of energy efficiency measures nonetheless.

Table III-1. Market Failures and Market Barriers Inhibiting Greater Energy Efficiency

Market failures	Market barriers
Unpriced costs and benefits	Low priority of energy issues
Distortionary regulatory and fiscal policies	Incomplete markets for energy efficiency
Misplaced incentives	Capital market barriers
Insufficient and inaccurate information	

Source: Brown 2001.

[10] No attempt was made to rank the various market failures or barriers by importance in this list or in the subsequent discussion.

B. Market Failures

Environmental externalities are one of the most important and frequently cited examples of unpriced costs and benefits. Energy prices do include costs associated with meeting environmental standards. But remaining adverse environmental impacts, such as emissions of mercury or carbon dioxide, land disruption, or legal water contamination, are not factored into energy prices. Likewise, the cost paid by society to protect and defend oil and other energy imports is not included in energy prices. As a result, more fossil energy is consumed than is socially optimal (Brown 2001).

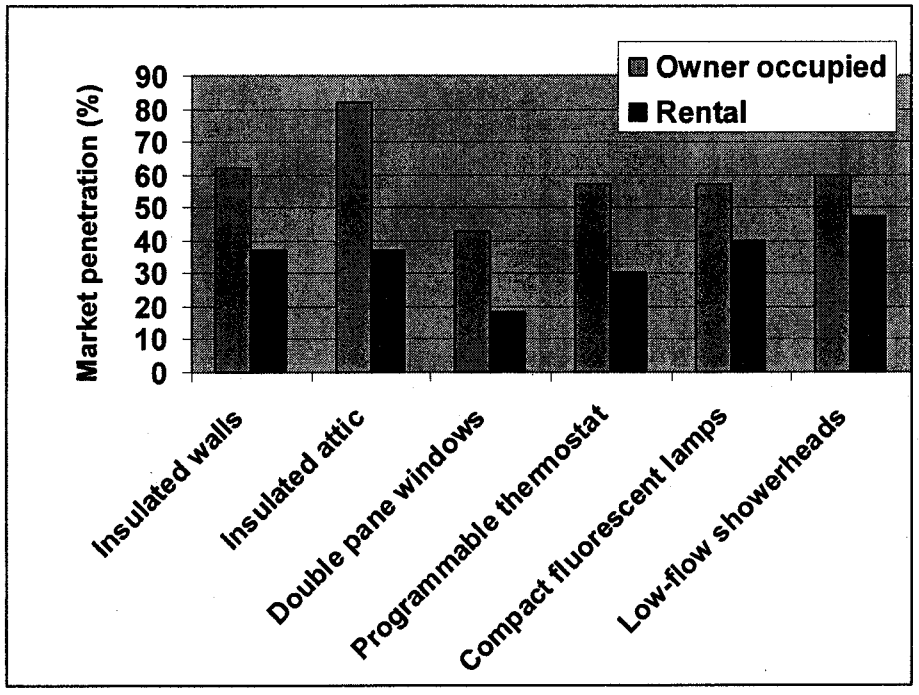
Many energy economists acknowledge that not including environmental and social costs in energy prices is a problem. For example, Jaffe and Stavins (1994) state, "While much controversy surrounds the magnitude of the value of the environmental damages associated with energy use, the direction of the effect is unambiguous. ...consumers face incentives to use more energy than is socially desirable if they do not bear the full costs of the pollution their energy use fosters."

There are also barriers to recognizing and taking into account the full benefits of energy efficiency measures in consumer and business decision making. For example, small increments of load reduction can have a significant effect on the market clearing price for electricity or natural gas in tight, competitive markets. This energy price benefit accrues to all consumers or businesses, not just those who take energy savings actions. In aggregate the benefit can be large, but it is both highly dispersed and not captured by those who cause it (Elliott and Shipley 2005; Wiser, Bolinger and St. Clair 2005).

Various types of fiscal or regulatory policies discourage investments in energy efficiency. For example, capital investments in commercial buildings must be depreciated over more than 30 years, while energy purchases can be fully deducted from taxable income the year they occur (Brown 2001). This means that tax policy discourages investment in energy saving measures. Likewise, regulatory policy that allows public utilities to increase their profits by selling more electricity or natural gas is a disincentive to effective utility energy efficiency programs (Carter 2001).

Misplaced incentives, also known as split incentives, exist in rental markets where building owners are responsible for investment decisions but tenants pay the energy bills. A number of studies have revealed lower levels of energy efficiency in dwellings occupied by renters compared to those occupied by owners in the United States (Train 1985). For example, a recent survey in California found that insulation, energy-efficient windows, programmable thermostats, and other energy efficiency measures are less common in rental housing compared to owner-occupied dwellings (see Figure III-1). Misplaced incentives also are found in construction markets where decisions about building design and features are made by people not responsible for paying the energy bills (Brown, Southworth, and Stovall 2005).

Figure III-1. Comparison of the Market Penetration of Energy Efficiency Measures in Owner-Occupied and Rental Housing in California (CEC 2004)



There is a large body of research documenting that consumers are often poorly informed about technology characteristics and energy efficiency opportunities. Some consumers do not know where to find credible information on energy efficiency options. Consumers may know how much more an energy-efficient air conditioner or water heater costs, but they do not know how much they will save per year by purchasing the more efficient technology. In addition, it can take many years to inform and educate a large majority of households and businesses about energy efficiency options. For example, after nearly eight years of active promotion of and at times incentives for compact fluorescent lamps (CFLs), nearly one-third of households surveyed in the Pacific Northwest in late 2004 were still unaware of this energy efficiency measure (Rasmussen, Geopfrich, and Horkitz 2005).

Likewise, consumers often lack the ability or time to process and evaluate the information they do have, a situation sometimes referred to as "bounded rationality" (Golove and Eto 1996). For example, consumers often have difficulty using information on energy labels or calculating the payback period for a more efficient appliance (Sanstad and Howarth 1994). Even when performance ratings are available (such as ENERGY STAR® labeling), consumers may not know how the energy-efficient device will function and how much energy and money will be saved in their own homes or businesses.

Consumers or businesses may perceive (rightly or wrongly) that energy efficiency technologies do not perform as well as the standard, less-efficient products they are used to. For example, consumers may believe that energy-efficient fluorescent lamps provide poorer quality light compared to incandescent lamps, that energy-efficient homes have poorer air quality and are less healthy than leaky, inefficient homes, or that energy-efficient furnaces or air conditioners are less reliable than "low tech" standard efficiency models (Jaffe and Stavins 1994). Likewise, businesses may be concerned that energy-efficient devices are less reliable and could lead to costly down time.

C. Market Barriers

Turning to the market barriers, businesses tend to pay limited attention to energy use and energy savings opportunities if energy costs are a small fraction of the total cost of owning or operating the business or factory or if energy efficiency is not viewed as a priority by company management. Energy costs represent less than 2% of the total cost of operating a factory or commercial business in many (but not all) cases. Many businesses have cut back on staffing and have few if any staff dedicated to energy and facility management. Furthermore, businesses are most concerned with developing new products, maintaining production, and increasing sales; energy consumption is usually a secondary or tertiary concern. As a result of these factors, many businesses limit energy efficiency investments to projects with payback periods of no more than two or three years (DeCanio 1993; Geller 2003).

Many individual consumers also do not value the lifetime energy savings provided by more efficient appliances, vehicles, or other energy efficiency measures. For example, consumers on average expect vehicle fuel efficiency improvements to pay back their first cost in three years or less even though vehicles remain in use for about 14 years on average (Greene and Schafer 2003).

Regarding incomplete markets for energy efficiency, some measures are relatively new and are still not widely available in the marketplace or not well-supported by product providers (Hall et al. 2005). These include measures such as highly-efficient light fixtures, reflective roofing materials, heat pump water heaters, and modern evaporative coolers. Also, some very effective energy efficiency services such as duct testing and sealing and existing building re-commissioning are not widely available or marketed in many parts of the WGA region.[11]

Regarding lack of capital to invest in energy efficiency measures, this is particularly a problem for low-income households that have limited resources and limited access to credit. In addition, some businesses (particularly small businesses) have insufficient capital or borrowing ability.

Detailed studies of particular markets have found multiple and substantial barriers inhibiting the adoption of cost-effective energy efficiency improvements. In the motors

[11] It should be noted, however, that some energy efficiency measures such as insulation, compact fluorescent lamps, or ENERGY STAR appliances are readily available.

market, for example, motor suppliers may fail to stock high efficiency motors, buyers may lack accurate information on motor efficiency or other opportunities for cost-effectively saving energy in motor systems, facility managers often shy away from newer technologies fearing reliability problems, and motors may be replaced on an emergency basis resulting in little or no time to consider energy efficiency (Nadel et al. 2002). Also, many motors are purchased by so-called Original Equipment Manufacturers (OEMs), companies that assemble pumps, blowers, air conditioning systems, etc. OEMs generally purchase motors based on lowest first cost since they are not responsible for paying operating costs, another example of "split incentives."

D. Implications

There are particular policy and program remedies to most if not all the market failures and barriers described above (Hall et al. 2005). These include educating consumers and businesses, increasing the supply and visibility of energy-efficient products and services in retail establishments, offering consumers and businesses financial incentives to get their attention and stimulate greater willingness in adopting efficiency measures, offering technical assistance, removing inefficient products or buildings from the marketplace through codes and standards, and reforming pricing and regulatory policies.

It is true that there are transaction costs related to educating consumers, addressing the split incentives problem, or convincing households or businesses to invest in energy efficiency to a greater degree. The real question is whether policy and program interventions are cost-effective mechanisms for stimulating greater investment in energy efficiency measures; i.e., whether the value of the energy savings, peak demand reduction, and non-energy benefits exceeds the costs (both for the efficiency measures and policy or program implementation). As explained in Chapter IV, many types of energy efficiency policies and programs are effective and economically attractive ways of removing or reducing the market failures and barriers described above.

IV. Best Practice Policies and Programs

The WGA states are implementing a wide range of policies and programs to advance energy efficiency (see Table IV-1 at the end of this chapter for a summary of these efforts). This chapter presents the best practices among energy efficiency policies and programs that already exist in the WGA region. It covers a wide range of successful efforts, but is not an exhaustive review of all efforts that could conceivably be deemed exemplary. Also, we believe that while all of these policies and programs have demonstrated (or are demonstrating) success, there is still room for further improvement in many of them.

This review is organized around the following 10 categories:

- Electricity Energy Efficiency Programs
- Natural Gas Energy Efficiency Programs
- Building Energy Codes and "Beyond Code" Programs
- Appliance Standards
- Research and Development (R&D) and Technology Transfer
- Public Sector Initiatives
- Tax Credits and Other Financial Incentives
- Regulatory and Pricing Policies
- Regional Cooperation and Market Transformation
- Energy Efficiency as an Air Pollution Control Strategy

A. Electricity Energy Efficiency Programs

1. California Investor-Owned Utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric)[12]

Energy savings: Energy efficiency programs implemented by California's investor-owned utilities during 1976-2000 provided about 17,000 GWh/yr of electricity savings in 2000, equivalent to 7% of statewide electricity use that year. Programs implemented in 2004 alone saved over 1,800 GWh/yr, equivalent to nearly 1% of retail sales by the three utilities. By 2013, the cumulative savings from utility energy efficiency programs implemented during 2004-2013 is expected to total more than 23,000 GWh per year. If this goal is achieved, it would cut the growth in consumption and peak demand by more than half and would begin to reduce per capita consumption of electricity. In other words, by 2013 the energy efficiency programs will save more electricity than San Diego Gas & Electric currently supplies every year to its 1.3 million customers. The peak savings from the programs are expected reach nearly 5,000 MW by the end of the ten-

[12] PUC Sets Electricity and Natural Gas Savings Goals for Utilities as Outlined in State's Energy Action Plan, press release, Docket # R01-08-028, California Public Utilities Commission, Oct. 13, 2004; California Public Utilities Commission, decisions D.03-12-060, D.04-02-059, and D.04-09-060; Utility applications for approval of 2006-08 portfolios.

year effort, equivalent to the output of ten large power plants. California's annual electricity savings will reach 1% of total annual load by 2007.

Program budgets: $1.73 billion is budgeted for 2006-2008 (three-year total). Program funding in 2004-05 was $732 million (two-year total).

Funding mechanism: $228 million per year is funded out of the state's non-bypassable public goods charge, while the remaining approximately $349 million per year is funded out of the general procurement budget along with all of the other energy resources relied upon to provide customer energy services. California requires its utilities to pursue cost-effective energy efficiency measures as the first resource to provide customer energy services. The utilities are expected to invest nearly $6 billion in energy efficiency programs over the next decade, with a total of $1.6 billion coming from the non-bypassable public goods charge.

Economics: The cost of energy efficiency programs over their lifetime has averaged $0.02-0.03 per kWh, less than half the cost of avoided generation. The programs are expected to provide about $10 billion in *net* benefits to the state's consumers over the next decade.

Programs: *Residential*: The residential lighting program offered rebates to manufacturers and retailers for ENERGY STAR® CFLs, torchieres, fixtures and ceiling fans to "buy down" the cost for customers. Other programs offer prescriptive rebates for energy-efficient products including HVAC, home improvement, appliances, and pool pumps. *Nonresidential*: The Standard Performance Contract program offers fixed-price incentives (by end-use) for measured energy savings. The Savings By Design program provides incentives for building owners and their design teams to use either a whole building or systems approach to increase energy efficiency in new construction and renovation/remodel projects. *Crosscutting*: The Codes and Standards Advocacy program provides technical and economic analyses to support upgrades to California's building codes and appliance standards.

2. PacifiCorp - Utah[13]

PacifiCorp is a large investor-owned utility that provides close to 80% of the electricity sold at the retail level in Utah through its Utah Power subsidiary. PacifiCorp is ramping up its DSM programs in Utah and expects to spend $21 million (about 2.0% of revenues) on these programs in 2005, up from $10 million in 2003 and $17 million in 2004. The programs include incentives for high efficiency air conditioners, evaporative coolers, and air conditioner cycling controls, incentives for energy-efficient new construction, technical assistance and incentives for all types of efficiency measures implemented by businesses, and an industrial self-direction program.

[13] *Integrated Resource Plan 2003,* PacifiCorp, Portland, OR; personal communication with Jeff Bumgarner, PacifiCorp, Portland, OR.

The 2004 DSM programs are projected to reduce peak demand by about 58 MW and save about 91 GWh/yr of electricity. With an emphasis on peak demand reduction, the programs are very cost effective with an average levelized cost of saved energy of about $0.02 per kWh.

3. Austin Energy - Texas[14]

Austin Energy is a publicly-owned utility serving around 350,000 customers in Austin, Texas. Austin Energy has implemented a wide range of energy efficiency programs for all of its customers for over two decades. These programs on a cumulative basis have reduced peak demand by 600 MW; something the utility calls its "conservation power plant." Austin Energy currently spends about $22 million per year on its energy efficiency and load management programs, about 3% of its revenues.

The programs are comprehensive and include rebates, low-interest loans, technical assistance, training and promotion of green building practices, and free retrofits for low-income households. Since 1982, there have been 374,000 residential participants, and all of Austin Energy's top 200 commercial customers have participated in energy efficiency programs. In recent years, over 30,000 households participated each year. Austin Energy has won national awards for its sustained energy efficiency efforts. In 2003, Austin Energy adopted a new strategic plan with ambitious energy efficiency and renewable energy goals. The plan calls for an additional 15% energy savings from energy efficiency programs by 2020.

4. Puget Sound Energy - Washington[15]

Puget Sound Energy is an investor-owned utility serving nearly one million electric customers in the Puget Sound region. The utility has been expanding its energy efficiency programs in recent years. As of 2004, the utility spent about $25 million (approximately 2% of revenues) on its electricity efficiency programs and saved 173 GWh/yr (0.8% of retail electricity sales). Programs providing the most savings included commercial and industrial energy assessments and incentives, residential lighting rebates, and activities implemented through the Northwest Energy Efficiency Alliance. In addition, the utility implemented 11 pilot programs in 2004 in order to explore new energy efficiency technology and program options. From a total resource cost perspective, the utility estimates its energy efficiency programs are saving electricity at an average cost of about $0.04 per kWh.

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[14] Austin Energy 2003 Annual Report; Austin Energy 2003 Strategic Plan; personal communication with Roger Duncan, Austin Energy; www.austinenergy.com.

[15] Semi-Annual Report for Demand Side Management (DSM) Programs January-December, 2004. Puget Sound Energy, Bellevue, WA,F eb. 15, 2005.

5. Seattle City Light - Washington[16]

Seattle City Light (SCL) is a publicly-owned utility serving over 360,000 customers in Seattle, Washington. SCL spent $20 million per year on its energy efficiency and load management programs on average during 2000-04, equivalent to 4.1% of its sales revenue during this four-year period. The utility spent an average of 5.8% of its revenues on these programs during 1977-2003. Approximately 70 staff work on these programs.

SCL's energy efficiency programs include energy-efficient appliance and lighting rebates, new construction design assistance and incentives, retrofits for low-income households, and rebates for efficiency measures implemented by businesses. In recent years, the programs have reduced electricity consumption by 72 GWh/yr (0.8% of electricity sales) on average. The estimated electricity savings in 2003 due to cumulative DSM efforts was 889 GWh, equivalent to 10% of SCL's total electricity sales.

There were over 580,000 participants in these programs during 1977-2003. In 2001, the utility offered conservation kits that included two compact fluorescent lamps (CFLs) and energy/water conservation measures to all of its residential customers. Kits were requested by 178,500 households, 57% of all customers at the time. A follow-up survey found that 94% of the CFLs were installed and used.

SCL's customers reduced their electricity bills by about $59 million in 2003 alone as a result of this sustained DSM effort. In 2003, the average utility incentive cost was $0.013 per kWh saved over the lifetime of installed conservation measures, less than one-quarter SCL's average electricity price. In nominal dollars, conservation programs saved SCL's customers $370 million on their electricity bills during 1977-2003.

B. Natural Gas Energy Efficiency Programs

1. California Investor-Owned Utilities (Pacific Gas & Electric, Southern California Gas Company, and San Diego Gas & Electric)[17]

Energy savings: Energy efficiency programs implemented by California's investor-owned gas utilities in 2004 alone saved about 21 million therms of natural gas. The California PUC has directed the utilities to greatly scale up their gas DSM programs, with goals of savings over 50 million therms per year starting in 2009. By 2013, the cumulative effect of the programs implemented during 2004-2013 is expected to be 444 million therms of savings per year, equivalent to the consumption of one million households and cutting California's growth in end-use gas consumption almost in half.

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[16] Energy Conservation Accomplishments: 1977-2003, Seattle City Light; www.cityofseattle.net/light/conserve.

[17] California Public Utilities Commission decisions D.03-12-060, D.04-02-059, and D.04-09-060; utility applications for approval of 2006-08 portfolios.

Program budgets: The California gas utilities are planning to spend $333 million for gas DSM programs during 2006-2008 ($110 million per year on average). Funding during 2004-2005 was about $55 million per year.

Funding mechanism: Funding is provided through the state's non-bypassable public goods charge for natural gas. Looking forward, additional energy efficiency program funding will be provided from general procurement budgets.

Economics: The CPUC directed utilities to reflect the natural gas savings targets in any applications for supply-side procurement or pipeline needs. This will ensure that the savings properly offset traditional supply-side resources. As the savings from the efficiency programs are less expensive than procuring natural gas, the Commission's decision is the first step to enable efficiency programs to compete for the utilities' procurement funding.

Programs: For residential customers, the programs include home energy audits, rebates for efficient gas-fired equipment, and incentives for efficient new homes. For non-residential customers, the programs include energy audits, prescriptive rebates for efficient equipment, a standard offer that pays a set rebate per therm saved for custom retrofits by larger customers, new construction design assistance and incentives, green building design assistance, and education and training for contractors. The portfolio also includes funding for emerging technologies, technical assistance and advocacy to upgrade the state's building codes and appliance efficiency standards, and support for better code enforcement.

2. Northwest Natural Gas and Energy Trust of Oregon

The Energy Trust of Oregon (ETO) is a statewide entity now implementing energy efficiency programs on behalf of gas and electric utilities in Oregon. The utilities collect a public benefits charge from ratepayers and pass funds to the ETO. The ETO is implementing programs to encourage home and commercial building retrofit, installation of efficient gas appliances, and efficient new construction. The savings as of 2004 in the Northwest Natural Gas service area were approximately 800,000 therms per year, equivalent to about 0.25% of total gas sales. In the case of Northwest Natural Gas, the state has adopted a decoupling mechanism so that the utility is not penalized financially if the ETO implements effective energy efficiency programs (see Section H below).

C. Building Energy Codes and "Beyond Code" Programs

1. Building Codes and Standards[18]

California: California's Title 24 building efficiency standards are the most stringent and comprehensive mandatory statewide building codes in the nation. California law authorizes the California Energy Commission (CEC) to establish energy efficiency

[18] Information on the status of building efficiency codes by state is available at www.bcap-energy.org/map_page.php.

standards for new buildings and major alterations and additions, which are referred to as Title 24. The legislation requires all CEC regulations to be cost-effective, meaning any incremental purchase costs are offset by the resultant energy bill savings. The code has separate sections for residential and commercial buildings, and is updated approximately every three years through a formal proceeding that provides multiple opportunities for stakeholder participation and feedback.

Title 24 divides the state into 16 climate zones and sets differing requirements for climate-sensitive measures such as insulation, windows, and heating/air conditioning systems by climate zone. The code offers two compliance options: prescriptive and performance-based. The prescriptive approach lists a specific package of measures that must be utilized. This option makes it very easy for builders to understand what to install and also makes compliance verification simpler. Under the performance-based approach, the builder is provided with an energy budget that is based on the amount of energy that the proposed building *would have used* if it met the prescriptive requirements. Energy use is measured based on energy cost, so the high value of saving peak power is taken into account. The performance-based approach provides the builder with greater design flexibility and the potential to reduce the cost of compliance.

Over 80% of all homes built in California take advantage of the performance-based approach. The most recent revisions to the Title 24 standards, adopted in 2005, will cut energy use in newly-constructed California buildings by approximately 10% and will provide about 180 MW per year in peak demand savings. California's Title 24 standards have saved consumers and businesses nearly $56 billion in electricity and natural gas costs since 1978. It is estimated that the standards will save an additional $23 billion by 2013.[19]

Idaho, Kansas, Montana, Nebraska, New Mexico, Oregon, Texas, Utah, and Washington: These states have all adopted by law the International Energy Conservation Code (IECC), published in 2003, or a customized energy code at least as stringent as this version of the IECC. In each of these states, the code establishes the mandatory minimum level of efficiency for new residential and commercial buildings and additions or renovations to existing buildings.[20] The IECC is published and maintained by the International Code Council, a non-profit organization. The IECC is revised on a regular cycle through an open public-hearing process sponsored by the International Code Council. Similar to California's Title 24 standards, the IECC has both prescriptive and performance-based compliance approaches. While many states have adopted the 2003 IECC, 2004 and 2006 versions of the IECC are now available for consideration and adoption.

2. Training and Compliance Programs

California: The state's major utilities provide training for local code compliance officials, as well as for architects, engineers, and specifiers, to provide timely information

[19] See http://www.energy.ca.gov/title24/ for details.

[20] In addition to the states mentioned here, all major jurisdictions in Nevada recently adopted the 2003 IECC.

about implementation of code changes. These programs are part of the utilities' energy efficiency portfolios and help ensure high compliance with the state's building standards.

***Texas*:** Energy code training is provided by the Texas A&M Energy Systems Laboratory and the State Energy Office. A combination of federal and state funding is used to support this effort.

3. Programs Promoting Highly-Efficient New Buildings

Many states and utilities implement programs to encourage architects and builders to exceed minimum energy code requirements. These programs typically provide training and technical assistance to builders and contractors, as well as promotion and consumer education. In some cases, financial incentives are offered to builders or homeowners for constructing/buying buildings that exceed the minimum code requirements. In the residential sector, many of these programs promote construction of ENERGY STAR (or "beyond ENERGY STAR") new homes.

Arizona: The Arizona Energy Office has a very active program promoting highly efficient home construction primarily in the Phoenix and Tucson metro areas. The effort centers on training builders and contractors. Also, utilities in Arizona have been active in encouraging builders to construct new homes that are at least 30% better than the Model Energy Code. The U.S. EPA estimated that 14% of new homes built in Arizona in 2004 qualified as ENERGY STAR homes.

Texas: Texas has active new construction commissioning and retro-commissioning (existing construction) programs that save from 10-20% of total energy use, optimize operations, and improve comfort. Texas A&M's Energy Systems Laboratory has commissioned over 300 large buildings with savings of $70 million since 1992. Oncor's Texas ENERGY STAR Homes program encourages builders to produce ENERGY STAR-rated homes by providing incentives to builders, marketing, advertising, training and support for HERS raters. In addition, the North Central Texas Council of Governments in the Dallas-Ft. Worth area has recommended regional adoption of energy codes 15% above the current statewide energy code.

California: Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric's Savings By Design program provides incentives for building owners and their design teams to use either a whole building or systems approach to increase energy efficiency in non-residential new construction and renovation/remodel projects. The California utilities also offer an ENERGY STAR new homes program and are partnering with local governments to provide expedited permitting for buildings that exceed minimum code.

Nevada: Nevada has a very effective ENERGY STAR new homes program that is co-sponsored by the state energy office, U.S. EPA and DOE, the state's utilities, and the Las Vegas area home builders association. The program includes builder training, cooperative advertising, and other educational activities. Nearly 50 builders participate in

the program, with approximately 50% of new homes built in the Las Vegas metro area being ENERGY STAR-certified as of 2004. This is the highest market share for ENERGY STAR homes in the country.

D. Appliance Standards

California: California's Title 20 appliance efficiency standards are the most stringent and comprehensive state standards in the nation. California law authorizes the California Energy Commission (CEC) to establish energy efficiency standards for appliances sold in California that are not regulated by the federal government. The legislation requires all CEC regulations to be cost-effective, meaning any incremental purchase costs are offset by the resultant energy bill savings. The CEC's regulations require manufacturers to submit energy performance data for certain products, and in some cases require the manufacturer to test its product's energy use or efficiency and to provide this information on the package to help inform consumers during their purchasing process. The Title 20 standards also establish minimum efficiency performance levels that covered products must meet in order to be sold in California. The Title 20 standards cover a wide range of products, including:

Air Conditioners	Indoor and Outdoor Lighting
Boilers	Plumbing Fixtures
Clothes Dryers	Pool pumps
Clothes Washers	Power Supplies
Commercial Ice Makers	Refrigerators and Freezers
Consumer Audio and Video Equipment	Small Water Heaters
Dishwashers	Traffic Signals
Distribution Transformers	Vending Machines
Electric Motors	Water-Source Heat Pumps
Exit Signs	Wine Chillers
Furnaces	

Some of these products are now covered by federal efficiency standards, adopted after California began regulating their energy performance. According to CEC estimates, standards enacted in California in 2001 and 2004 will save consumers and businesses $2 billion by 2020. Once the current installed base of covered products is replaced, these standards will save 5,100 GWh of electricity per year, 1,200 MW of peak demand, and 53 million therms of gas per year (Mahone et. al. 2005).

Arizona, Oregon and Washington: All three states recently adopted new appliance efficiency standards covering some of the products regulated by California. The new standards set minimum efficiency levels for commercial ice makers, commercial clothes washers, pre-rinse spray valves, commercial refrigerators and freezers, exit signs, large packaged air conditioners (Arizona only), distribution transformers, metal halide lamp fixtures, power supplies, incandescent reflectors (Oregon and Washington only), torchieres, traffic signals, and unit heaters.

E. Research and Development (R&D) and Technology Transfer

A number of states throughout the country support R&D on energy-efficient technologies and technology transfer. Among western states, noteworthy efforts occur in California and Washington.

California: The California Energy Commission's Public Interest Energy Research (PIER) program invests in R&D to increase the energy efficiency of electric and natural gas technologies and services in the state.[21] Funding is provided through the state's electricity public goods charge, and by investor-owned natural gas utilities. The California Institute for Energy Efficiency (CIEE) supports public-interest energy research in California, including energy efficiency research. CIEE makes use of R&D expertise at California's universities as well as the national laboratories. As of 2004-05, CIEE and the PIER program were developing a wide range of technologies including natural cooling systems, high efficiency air conditioners designed for hot, dry climates, new types of evaporative cooling systems, light emitting diodes (LEDs), and new HVAC and lighting control devices.

Washington: The Washington State University Energy Program (WSUEP) is a self-supporting department within the university's Extension Service. It is funded by the U.S. DOE, the Bonneville Power Administration, Northwest Energy Efficiency Alliance, and other sources. Among its activities, the WSUEP provides best practices training for industries throughout the northwest region and targeted technical assistance to individual companies. WSUEP also conducts field research and testing on issues such as indoor air quality and moisture problems in buildings, and supports implementation of the state's building energy code through training and consumer education.[22]

F. Public Sector Initiatives

Arizona: In April 2003, Governor Napolitano signed into law House Bill 2324 which directs state agencies and universities to achieve a 10% reduction in energy use per unit of floor area by 2008, and a 15% reduction by 2011; purchase cost-effective ENERGY STAR or Federal Energy Management Program-designated energy-efficient products; and meet energy conservation standards developed by the Arizona Department of Commerce's Energy Office. It is estimated that this policy will reduce energy costs in state facilities by $90 million during 2004-2015.

California: In December 2004, Governor Schwarzenegger issued a green buildings Executive Order requiring that all new and renovated state buildings achieve environmental ratings of LEED™ (Leadership in Energy and Environmental Design Green Building Rating System) Silver level or higher, setting a goal for all state buildings to be 20% more efficient by 2015, and encouraging the private sector to do the same.[23]

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[21] See http://www.energy.ca.gov/pier/ for details.
[22] See http://www.energy.wsu.edu/ for details.
[23] Executive Order S-20-04, December 14, 2004.

Colorado: Colorado adopted legislation in 2001 to facilitate use of energy service companies (ESCOs) and performance contracting by state agencies. Since then, considerable progress has been made in using ESCOs to implement energy efficiency projects in state and local government buildings as well as in public schools. Also, Governor Owens issued an Executive Order in 2005 calling for new and renovated state buildings to be built to LEED standards.

Kansas: The Facility Conservation Improvement Program (FCIP) retrofitted about 50% of all state facilities over five years using a streamlined performance contracting model. The Program is now starting to benchmark the energy performance of all public school buildings using the U.S. EPA's Portfolio Manager System.[24]

Texas: The Texas LoanSTAR revolving loan program was begun in 1989 by the Governor's Energy Office. It provides low-interest loans for energy-conserving retrofits made in state, county and local government buildings and independent school districts. The program allows qualified borrowers to repay loans through the estimated stream-of-cost savings generated by energy efficiency projects. It can now be used to fund projects identified by energy service companies as well as leverage other local funds.

The original $98.6 million fund has "revolved" 2.3 times and funded 182 loans for $227 million, with $152 million in cumulative energy bill savings as of December 2004. Extensive measurement and verification from utility bills and/or sub-metering has been a program hallmark and served as the basis for many of the procedures found in the widely used International Performance Measurement and Verification Protocol. Program administrative fees, design and construction oversight, and reporting are all paid from a 3% annual interest rate on the outstanding loan balances.

G. Tax Credits and Other Financial Incentives

Oregon: Oregon provides residential tax credits for premium efficiency appliances including dishwashers, clothes washers, and refrigerators; efficient heating and air conditioning systems, including air conditioners, furnaces, and duct testing and sealing; and efficient water heating systems. The state also provides businesses tax credits for retrofits of energy-using equipment that yield a 10% increase in efficiency except for lighting retrofits which must yield a 25% increase in efficiency; weatherization of rental units; and new commercial buildings that achieve a U.S. Green Building Council's LEED (Leadership in Energy and Environmental Design) rating. The Oregon tax incentives have been in place for more than two decades, and the Oregon Office of Energy analyzes and revises the qualification thresholds. The total cost to the state for these tax credits is about $35 million per year. Energy savings information is not available.

Arizona: Arizona provides an income tax deduction for the purchase of homes that are certified to be 50% more energy efficient than the 1995 Model Energy Code.

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[24] For details, see http://www.energystar.gov/index.cfm?c=evaluate_performance.bus_portfoliomanager.

Idaho: Idaho provides income tax deductions for home insulation.

Montana: Montana provides tax credits for making new and existing homes more energy-efficient through weatherization or replacement of heating, cooling, or water heating systems. The state also provides corporate tax deductions for energy-efficient space and water heating systems and any income received from royalties related to patents that encourage energy savings.

Nevada: Legislation adopted in Nevada in 2005 reduces property taxes on new commercial buildings that are built and certified to at least the LEED silver standard. The details of this innovative and potentially influential policy were still being worked out as of October, 2005.

H. Regulatory and Pricing Policies

1. Removing Financial Disincentives for Utility Energy Efficiency Programs

California: California Public Utilities Code Section 739.10, enacted in 2001, provides that the Commission must "ensure that errors in estimates of demand elasticity or sales do not result in material over or under collections of the electrical corporation." The California Public Utilities Commission now requires the state's investor-owned utilities (PG&E, SCE, SCG, and SDG&E) to use modest regular adjustments in electric and gas rates to break the link between the utilities' financial health and the amount of electricity and natural gas sold. This removes significant regulatory barriers to utility investments in cost-effective energy efficiency improvements, and helps align the interests of utility shareholders and customers.

Oregon: In June 2001, Northwest Natural Gas Company filed an application to request Commission approval of a mechanism to ensure the utility is not financially penalized as a result of energy efficiency efforts. The Public Utility Commission of Oregon subsequently adopted a settlement agreement establishing a decoupling mechanism for the natural gas utility.[25] The decoupling mechanism prevents the utility's net revenues and profits from declining if its DSM programs are successful.

New Mexico: New Mexico enacted legislation in 2005 that directs electric and gas utilities to implement cost-effective energy efficiency programs. The legislation also instructs the state utility commission to remove any financial disincentives or barriers that inhibit utility expenditures for energy efficiency measures.

2. Integration of Energy Efficiency into Resource Planning and Procurement

California: The California PUC requires investor-owned utilities to invest in energy efficiency as a resource, above and beyond investments through the public goods charge, whenever it is cheaper than building new power plants. The Energy Action Plan, endorsed by Governor Schwarzenegger and adopted by the California PUC and the

[25] Public Utility Commission of Oregon, Order No. 02-634, 2002.

California Energy Commission, establishes a "loading order" of preferred energy resources, placing energy efficiency as the state's top priority energy resource, followed by renewable energy generation.[26]

A revised plan, known as Energy Action Plan II, was adopted in October, 2005. It reiterates and strengthens California's commitment to utility energy efficiency programs, building energy codes, appliance standards, and other policies that will maximize the realization of cost-effective energy efficiency improvements in the state.[27] It also provides a coordinated implementation strategy for the broad range of energy efficiency efforts underway in the state.

Pacific Northwest: The Pacific Northwest Electric Power Planning and Conservation Act of 1980 authorized the four northwest states to form an interstate power planning agency. This agency develops 20-year regional power plans periodically, with cost-effective energy efficiency measures incorporated as the highest priority resource option. The energy efficiency component of the fifth regional power plan was described in Chapter II.

3. Public Benefits Charges

Arizona, California, Montana, and Oregon have public benefits charges that collect ratepayer funding for investment in energy efficiency programs as well as other programs that provide public benefits. The largest public benefits charges for energy efficiency programs in the West can be found in California, which collects 1.3 mills/kWh, Oregon with 1.26 mills/kWh, and Montana with 0.7 mills/kWh (Kushler, York, and Witte 2004).

4. Energy Saving Targets

California: The California PUC has established aggressive electricity and natural gas savings targets, and requires that the utilities meet or exceed these targets in pursuing all cost-effective energy efficiency.[28] The California PUC also requires that the energy efficiency program savings be measured and verified by independent evaluators.[29]

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[26] California Consumer Power and Conservation Financing Authority (CPA), California Energy Resources Conservation and Development Commission (CEC), and California Public Utilities Commission (CPUC), *Energy Action Plan,* adopted May 8, 2003 by CPUC; April 30, 2003 by CEC; and April 18, 2003 by CPA. Available online at www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF; letter from Governor Schwarzenegger to CPUC President Peevey, April 28, 2004.

[27] See Energy Action Plan II – Implementation Roadmap for Energy Policies, California Energy Commission and California Public Utility Commission, October, 2005. http://www.cpuc.ca.gov/word_pdf/REPORT/50480.doc.

[28] CPUC Decision No. 04-09-060.

[29] CPUC Decision No. 05-01-055.

5. Inverted Block Rates (also known as tiered rates)

California: California has inverted block rates for most residential customers, meaning the cost per kWh increases as electricity consumption increases. At the present time, basic residential tariffs are split into five tiers, with the highest consumption tier nearly twice as expensive per kWh as the lowest tier. This provides a strong incentive for conservation and efficiency investments, complementing other energy efficiency initiatives such as utility DSM programs and building energy codes.

Utah: Residential customers of Utah Power pay inverted block rates during the summer. Rates start at 6.9¢ per kWh for up to 400 kWh per month, 7.9¢ per kWh for the next 600 KWh, and 9.3¢ per kWh for usage over 1,000 kWh per month. This policy encourages energy efficiency particularly in the use of air conditioning.

Washington: Utilities in Washington including Puget Sound Energy, Avista, PacifiCorp, and Seattle City Light have inverted block rates, providing an incentive for conservation and efficiency investments. Puget Sound Energy, for example, charges residential customers 6.8¢ per kWh for the first 600 kWh per month, and 8.5¢ per kWh for electricity use in excess of this amount.

I. Regional Cooperation and Market Transformation

Northwest Energy Efficiency Alliance[30]

The Northwest Energy Efficiency Alliance (NEEA) is a non-profit organization supported by electric utilities, public benefits administrators, state governments, public interest groups and energy efficiency industry representatives. These entities work together to make affordable, energy-efficient products and services widely available in the marketplace in Idaho, Montana, Oregon, and Washington. NEEA was founded to complement – not replace – the strong tradition of state and local utility energy efficiency efforts in the region.

Projects: Many of NEEA's projects are aimed at increasing the supply of and demand for energy efficiency measures in the region, aiming to remove barriers inhibiting the adoption of efficiency measures in the marketplace. Projects target residential, commercial, agricultural, and industrial sectors. A number of the projects also provide information and training.

Energy savings: NEEA estimates its 2004 activities reduced electricity use in the region by 48 average MW (aMW), i.e., 420 GWh/yr. This is equivalent to about 0.25% of annual electricity use in the four-state region. By 2010, the NEEA and related utility efforts are expected to save the region over 500 aMW, enough to offset the need to build two new power plants (NEEA 2005).

Program budgets: From 1996 through 2004, $165 million was committed to NEEA by its funders. Starting in 2005, an additional $20 million a year has been pledged for five years through 2009.

[30] Northwest Energy Efficiency Alliance website, www.nwalliance.org.

Economics: savings to date (not counting savings that will continue to accrue from the long-term impact of sustained market changes) have cost NEEA between 0.8 and 1.2 cents per kWh, with a mean of 1.0 cent per kWh. These savings are cost-effective compared to the avoided cost of electricity that would otherwise have been purchased by utilities, which is on the order of 4 cents per kWh over the long-term. Moreover, the savings are at the low-end of costs from other types of conservation programs over the last five to 10 years, which have been about 2.1 cents per kWh according to the Northwest Power and Conservation Council.[31]

J. Energy Efficiency as an Air Pollution Control Strategy

Texas: The State Implementation Plan (SIP) for Clean Air Act compliance for Dallas-Fort Worth includes a number of energy efficiency and renewable energy projects brought about through the Texas Emissions Reduction Plan of 2001. Senate Bill 5 (SB5) requires counties surrounding Dallas-Fort Worth to implement all cost-effective energy efficiency measures with a goal of reducing electric consumption by 5% per year through 2007. Texas developed a methodology and historical generation data base for quantifying emissions benefits (the Texas Emissions and Energy Calculator, eCalc) with the help of Texas A&M University's Energy Systems Laboratory, the Texas Commission on Environmental Quality, the Texas Public Utilities Commission, and the U.S. EPA.[32] Texas estimates the emissions reductions from new and existing efficiency and renewable energy programs will be as much as 16 tons of NO_x per peak ozone day by 2010. Also, it is anticipated that Texas will include NO_x reduction credits from other major energy efficiency and renewable energy initiatives in future SIPs.

Region-wide: Regional modeling sponsored by the Western Regional Air Partnership (WRAP) found that a combination of energy efficiency and renewable energy (EE/RE) measures could yield reductions of 1-2 % in NO_x emissions and 10-14% in CO_2 emissions by 2018, and up to $7 million in SO_2 compliance savings. Five western states (Arizona, New Mexico, Oregon, Utah and Wyoming) have since submitted regional haze SIPs that include one or more EE/RE programs as pollution control strategies. Demonstration of the contribution EE/RE programs make to short- and long-term emissions reductions and visibility improvements is required by EPA's regional haze rule. States that filed SIPs are developing methodologies to estimate and track emissions reductions from EE/RE programs.

[31] NEEA's low cost of energy savings is due mainly to the large number of very cost-effective CFLs that the program promoted in recent years.
[32] See http://ecalc.tamu.edu/ for details.

Table IV-1. Summary of Energy Efficiency Policies and Programs in the 18 WGA States

	Utility Energy Efficiency Programs and Incentives				Up-to-Date Building Codes				
	EE Program - - Electricity	EE Program – Natural Gas	Public Benefits Fund	EE Goal *	Residential	Commercial	Appliance Standards	Public Building Programs	Tax Credits/ Deductions
AK					X			X	
AZ	X		X				X	X	X
CA	X	X	X	X	X	X	X	X	
CO	X							X	
HI	X			X				X	
ID	X	X			X	X		X	X
KS					X	X		X	
MT	X	X	X		X	X		X	X
NE					X	X		X	
NV	X			X	X	X		X	X
NM					X	X		X	
ND								X	
OR	X	X	X		X	X	X	X	X
SD								X	
TX	X			X	X	X		X	
UT	X				X	X		X	
WA	X	X			X	X	X	X	
WY								X	

*HI and NV allow for a portion of the requirements under their Renewable Portfolio Standards to be met by energy efficiency measures.

V. Analysis of Energy Efficiency Potential

A. Introduction

Two of the central objectives of the Energy Efficiency (EE) Task Force are to: (1) assess the impacts of current electricity efficiency efforts across the region, and (2) to assess the feasibility of the energy efficiency goal in the WGA's 2004 energy resolution. With support from the U.S. EPA, the Task Force analyzed these issues using a scenario-based approach and an integrated energy model.

Based on our own knowledge as well as consultation with other experts and available literature, the Energy Efficiency Task Force identified existing commitments to energy efficiency in the WGA region due to legislation, regulations, codes, standards, or mandated goals. We also compiled a set of "best practice" policies and programs from across the region, drawing heavily from our review in Chapter IV. We then considered the potential energy, economic, and environmental impacts of a "ramp up" to best practice across all states in the region. This chapter presents our analytical methodology and the results of this exercise.

B. Analytical Approach

Our analysis of energy efficiency potentials and impacts involves three discrete steps. First, we define three scenarios for regional energy efficiency: (1) a Reference scenario based on U.S. Department of Energy (DOE) projections; (2) a Current Activities scenario reflecting known regional, state and local programs and policies; and (3) a Best Practices scenario. Second, we establish the cost assumptions and other parameters for evaluating impacts. Third, we analyze the impacts of the Current Activities and Best Practices scenarios relative to the Reference scenario, using the U.S. DOE National Energy Modeling System (NEMS) along with spreadsheet analysis. These steps are described in the following subsections and in Appendix B.

1. Defining Scenarios

To estimate the impacts of current and potential future energy efficiency policies and programs in the WGA region, we construct three alternative scenarios for regional electricity consumption over the period 2005 to 2020. Each scenario is then evaluated in terms of its impact on electricity supply. The three scenarios are defined as follows:

- **Modified EIA Reference Case.** The Reference scenario projects electricity consumption using the key assumptions and drivers of the reference case of the Energy Information Administration's Annual Energy Outlook 2005 (AEO 2005) (EIA 2005). In preparing its projections, EIA evaluates "a wide range of current trends and issues that could have major implications for U.S. energy markets over the 20-year forecast period. Trends in energy supply and demand are linked with such unpredictable factors as the performance of the U.S. economy overall, advances in technologies related to energy production and consumption, annual changes in weather

patterns, and future public policy decisions." EIA develops its energy outlook using the *National Energy Modeling System* (NEMS), its national energy supply and demand model. We used NEMS for this analysis.

The primary modifications that we made to the EIA reference case were to include the estimated energy savings from: (1) the 2005 Federal energy bill and (2) some of EPA's ENERGY STAR® programs. The Federal energy bill was passed in August 2005, after EIA had prepared the AEO 2005 reference case. We used estimates provided by the American Council for an Energy-Efficient Economy for national electricity savings from the new Energy Act (ACEEE 2005). We interpolated the values between years and used a feature in NEMS to allocate savings pro-rata to each region.[33] Additionally, discussions with EIA and EPA staff along with review of NEMS input assumptions and detailed output indicated that the EIA reference case accounts for many federal energy efficiency programs. However, the Federal ENERGY STAR programs are not completely represented in the model. EPA staff provided the expected national energy savings from ENERGY STAR office equipment and residential electronic devices as an initial estimate of savings from some of the programs not currently reflected in the NEMS.[34] We also adjusted EIA's assumptions regarding reserve margins, to incorporate more recent analysis, as described in Appendix B.

- **Current Activities**. The Current Activities scenario adjusts the Modified EIA Reference Case scenario to account for the estimated impacts of ongoing and recently enacted energy efficiency policies and programs at the state, regional, or utility levels, in the WGA region. While EIA's Annual Energy Outlook includes the effects of energy efficiency policies adopted at the national level, such as Federal appliance efficiency standards, it does not effectively capture the effects of non-Federal energy efficiency policies and programs such as state or local building energy codes, or utility demand-side management (DSM) programs. This statement is based on conversations with EIA staff as well as a review of the EIA projections. For instance, AEO2005 projects electricity consumption in the Pacific region (Washington, Oregon, California, Alaska and Hawaii) to grow at an average of 2.2% per year from 2005 to 2020. However, demand projections from the California Energy Commission and the Northwest Power Planning Council, which cover 95% of Pacific region electricity use, indicate expected growth of 1.4% to 1.5% per year, after accounting for current state and local efficiency efforts.

  To estimate electricity savings from current or committed policies and programs, we collected as much information as possible about significant energy efficiency initiatives in any of the 18 WGA states. While some states have comprehensive

[33] It can be argued that the new appliance efficiency standards included in the 2005 Federal energy bill were enabled by adoption of these standards in California and other states, and thus the energy savings should continue to be credited to the states. The fact that we are attributing the savings to Federal action is thus conservative from the viewpoint of assessing energy savings potential at the state level.

[34] We are assuming that the energy savings effects from other ENERGY STAR products are captured to a substantial degree through the utility DSM programs underway or proposed for the region.

information on expected electricity savings and expenditures, others have limited data from which to estimate efficiency savings. In those cases, we use estimates of expected efficiency program expenditures together with historical data on energy savings per dollar expended for similar states or programs, or other simple estimation techniques.

In general, this scenario assumes continued support of current activities in the future. Unless there is a commitment to program expansion, we assume current policies and programs remain in place through 2020, and continue to achieve a constant level of incremental annual electricity savings (equivalent to the last year in currently available program plans or policy estimates). Table V-1 presents examples of current activities that have been included in this scenario. Further details on some of these policies and programs are provided in Chapter IV.

- **Best Practices.** This scenario assumes that all states in the WGA region adopt and implement energy efficiency programs and policies similar to today's best practices among the 18 states. To develop this set of best practice programs and policies, we reviewed leading current activities, as outlined in Table V-1 and presented in more depth in Chapter IV. For each program/policy category – appliance standards, DSM programs, building energy codes, market transformation programs, and public sector initiatives – we estimated the electricity savings (as a percentage of total consumption) associated with the top policies currently underway. We then assumed that other states and localities could ultimately – after several years of "ramp up" – achieve similar savings in percentage terms through well-designed and adequately-supported efforts.

  Table V-2 summarizes the assumptions used in this scenario. The examples presented in Chapter IV come from both rapidly and slower growing states, and we believe the savings values described in Table V-2 are possible in all states.[35] Note that for states that already have a wide array of ambitious programs, such as California, the electricity savings in the Best Practices scenario are not much greater than the savings in the Current Activities scenario. However, for most states, a significant gap exists between what is currently underway and what might be achieved through adoption of best practice policies and programs.

[35] Faster growing states present more opportunities for efficiency improvement in new construction, while slower growing states have an older building stock that offers substantial energy savings opportunities as well.

Table V-1. Examples of Current Activities

Appliance Standards	California has been at the forefront of setting appliance standards. In 2004 it upgraded its state standards to include nearly 25 products, including those for consumer electronics (reducing stand-by power use), pool pumps, general-service incandescent lamps, and commercial walk-in coolers and freezers. By 2020, these standards are expected to reduce electricity use by 1.5%, compared to the reference case. Arizona, Oregon,a nd Washington recently enacted minimum energy efficiency standards on a variety of residential and commercial appliances that are not covered by federal standards, replicating standards first adopted in California.
DSM Programs	The California Public Utilities Commission (CPUC) recently adopted the nation's most aggressive goals for electricity DSM programs for 2006-2013 for the state's three major investor-owned electric utilities (CPUC 2005). In June 2005, these utilities filed their estimates of expected savings from programs for 2006 to 2008 and these savings exceeded the CPUC goals by an average of 9% each year. The average expected savings for the three utilities is about 1% of total load per year, meaning 5% savings after five years of programs, 10% after 10 years, etc. Many other utilities in the WGA region have DSM programs with a range of budgets and energy savings levels. Several municipal utilities such as Austin Energy and Seattle City Light have achieved or expect to achieve energy savings of about 0.8% of total load.
Building Energy Codes	For building codes, we accounted for states or portions of states that have upgraded to a recent version of the International Energy Conservation Code (IECC), specifically a 2000 or later version of the code, or a customized version of the code which is the case in California. Since the Modified EIA Reference Case forecast includes minimal efficiency improvements in new homes, we assume adoption of the code leads to rather substantial energy savings.[36] However, we assume somewhat limited code enforcement and compliance with a savings realization rate of 70% on average.
Market Transformation	The Northwest Energy Efficiency Alliance (NEEA) implements a variety of programs aimed at increasing the efficiency of energy use in the northwest region (ID, OR, MT, and WA). This regional effort results in savings above and beyond that provided by utility DSM programs or building energy codes in the region (NEEA 2005).
Public Sector	Arizona adopted a requirement that state agencies and public universities reduce their energy consumption per square foot of floor area 10% by 2008 and 15% by 2011 (relative to levels in 2002). Also, Arizona Governor Napolitano issued an executive order in 2005 requiring all future state-funded buildings to meet the Silver Leadership in Energy & Environmental Design (LEED™) standard (Arizona State Government 2005). In 1989, Texas established a revolving loan fund known as the LoanStar program to finance energy efficiency projects in state and local government buildings, independent school districts, and higher education buildings. The original $98.6 million fund has provided 182 loans for $227 million, with cumulative energy bill savings worth $152 million as of December 2004.

[36] In particular, we assume adoption of a recent version of the IECC leads to 5% electricity savings on average in states in colder or moderate climates, and 13% savings in homes in very hot climates (AZ, TX, and NV). Regarding commercial buildings, we assume adoption of the code leads to 10% electricity savings in moderate and colder states, and 15% savings in very hot states (Kinney, Geller, and Ruzzin 2003). For California, we used estimates of the electricity savings from building code upgrades adopted in 2001 and 2005 (Mahone, et al. 2005). These savings levels are prior to the adjustment for savings realization mentioned in Table V.1.

Table V-2. Assumptions for Best Practices Scenario

Appliance Standards	This scenario reflects assumptions that: • states with no current appliance standards enact appliance standards similar to those already implemented in several WGA states, leading to annual energy savings of 0.10% (relative to total electricity consumption) per year (same level of savings as achieved by California).[37] • Washington, Oregon and Arizona maintain current appliance standards until 2009, then expand them to cover the additional appliances included in California's standards. • California deepens or expands its standards as needed to maintain annual energy savings at the 0.10% level achieved by current standards.[38]
DSM Programs	All electric utilities would aim to achieve 0.9% savings (relative to total consumption) annually, starting in 2007. Utilities with no current programs start with a lower goal (0.45%) in 2006. The goal of 0.9% represents a midpoint between the savings achieved by the best investor-owned utility (IOU) programs (1% per year) and the best municipal utility programs (0.8% per year).[39] These savings would be maintained through 2020.Si nce the CPUC goals for the three major IOUs in California, combined with continuation of current activities for other utilities, are expected to achieve 0.93% savings per year, the current activities of DSM programs in California already represent best practices and no additional savings are expected for this scenario.
Building Energy Codes	This scenario assumes that the International Energy Conservation Code, 2004 version, is adopted in 2007 in all states except California, as California has its own more stringent standard. It is assumed that state and/or local building energy codes are upgraded in 2011 (3% improvement) and in 2015 (additional 6% improvement). This scenario also assumes that compliance and enforcement are improved and that a 90% savings realization rate is achieved. Finally, we assume that California's current building energy codes will be upgraded in 2009 (3%), 2013 (6%) and 2017 (3%).
Market Transformation	By 2007, this scenario reflects the adoption by all WGA states of market transformation programs similar to those of the Northwest Energy Efficiency Alliance. NEEA programs achieve reductions in electricity consumption of about 0.2% per year (NEEA 2005), and this rate is assumed to apply to all states. These savings are in addition to those achieved through building energy codes and utility DSM programs.
Public Sector	It is assumed that all states adopt savings goals for public buildings, along with supporting financial and technical assistance initiatives, similar to those in place in Arizona. This scenario thus assumes that public buildings (state and local government buildings plus K-12 schools and higher education) reduce electricity use per square foot by 15% in 2020.

[37] Some of the California standards were adopted as federal standards in the 2005 federal energy bill. We have included the savings from the federal standards in the Reference scenario; the savings in the Best Practice scenario is an estimate of the savings potential if states adopt appliance standards not covered by federal standards.

[38] Once the stock of appliances covered by standards begins to fully "turn over," the rate of energy savings reaches a plateau. For the 2001/2004 California standards, this effect starts to be significant around 2017. Experience suggests that further, economically-beneficial opportunities to strengthen standards or cover new appliances will appear over time, and thus it is reasonable to assume that energy savings from standards will continue to occur through 2020.

[39] The best practices for IOUs are based on expected savings from 3 large IOUs in California, Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. Best practices for municipal utilities are based on Austin Energy and Seattle City Light (see Chapter IV).

2. Establishing Cost and Other Assumptions

Most assumptions used in this analysis for the electric sector – demand growth, fuel prices, power plant construction, operation and maintenance costs, transmission, financing – are drawn directly from the EIA's 2005 Annual Energy Outlook (see Appendix B for some of these key assumptions). However, EIA does not provide estimates of the cost of efficiency programs and policies. For these figures, we looked directly to experience and estimates from activities within the WGA region. Table V-3 shows the assumptions we used for the cost of saved electricity by policy or program type, along with the source for these assumptions. These costs reflect the total resource cost approach, meaning they include the full incremental capital costs of more efficient technologies plus any program development, implementation, and administration costs.

Table V-3. Cost of Saved Electricity Assumptions, Total Resource Cost Approach

Policy / Program type	cents/kWh (2005$)	source:
Appliance Standards	1.19	Average cost of appliance standards in Oregon and Washington, based on results from *Appliance Standards Awareness Project (2005)*
DSM Measures	2.50	Estimate based on *Funding and Savings for Energy Efficiency Programs in Program Years 2000 through 2004* (Rogers, Messenger, and Bender 2005) and the *Fifth Northwest Electric Power and Conservation Plan* (NPPC 2005)
Building Energy Codes	4.74	Based on estimate of 7 year pay back, discussions with staff of *Building Codes Assistance Project* and *Alliance to Save Energy*
Market Transformation	1.20	Total resource cost estimate from *Retrospective Assessment of the Northwest Energy Efficiency Alliance* (Violette, Ozog and Cooney 2003)
Public Sector	4.74	Based on estimated 7-year payback from review of LBNL/NAESCO database (Osborn et al. 2002)

For the net present value calculations, we first estimated annual values of all costs and benefits. The costs were estimated by multiplying annual electricity savings by the costs per kWh in Table V-3. For benefits we used annual estimates of avoided fuel costs, operating and maintenance costs, and transmission and distribution costs (as provided by NEMS output). We calculated avoided capacity in MW then multiplied by the overnight capital costs of units (see Appendix B). However, capital costs were then levelized as annual costs over the lifetime of the power plants, using a 5% real discount rate. These calculations combined to provide a stream of annual costs and benefits from 2005 to 2020. We then calculated the net present value of these costs and benefits, again using a 5% discount rate.

3. Modeling Impacts

The principal difference among the three scenarios considered is the extent of future energy efficiency activities, and their resulting impact on electricity supply requirements. Energy efficiency policies and programs in the Current Activities and Best

Practice scenarios entail equipment, program, and administrative costs, as just noted. They will also yield economic benefits as fewer power plants are needed to ensure reliable electricity supply, as less fuel is purchased and used, and as plant operation and maintenance costs are lowered. As noted above and described in more detail below, we use the NEMS model to estimate these impacts.

We begin by calculating electricity consumption for each scenario. Based on the assumptions described above, we estimate electricity savings from each policy or program area by state and by year, and then subtract these savings from electricity consumption in the modified EIA Reference forecast. For building codes, staff at the *Building Codes Assistance Project* developed estimates of the energy savings for each state in the Current Policies and Best Practices scenarios.[40]

We then use the electric market module of NEMS to simulate how the electric sector might respond to meet demand in each scenario. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. It contains, among other attributes, methods to characterize the evolution of power plant costs over time (including learning effects), resource supply curves for renewables as well as conventional fuels, and electricity load shapes. The assumptions and algorithms used in NEMS are continuously and widely reviewed by leading energy experts and economists across the U.S.[41]

For each projected year, NEMS seeks to determine the mix of new plant builds and dispatch that will meet electricity demand at the lowest cost, subject to environmental constraints. The key results from the model for this analysis are the types of new plants, the mix of generation, emissions resulting from generation and operations, electricity prices, and the total costs of the electric system (capital fuel, operating and maintenance, transmission, and distribution).

NEMS is a national model with regional disaggregation: the demand modules (e.g., residential, commercial, industrial, and transportation) are disaggregated into the nine Census divisions, and the Electricity Market Module consists of 15 supply regions based on the North American Electric Reliability Council (NERC) regions. The WGA states are subsumed within 6 of the 15 electricity regions.[42] To develop results specifically for the WGA region, we use the NEMS output from six electricity supply regions, then allocate electricity generation, energy consumption, and emissions to states based on their shares of electricity consumption in the corresponding NEMS/NERC

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[40] Personal communication with David Weitz, Building Codes Assistance Project, Providence, Rhode Island.

[41] For a more detailed description of NEMS, see *The National Energy Modeling System: An Overview 2003* (EIA 2003) and Appendix B of this report.

[42] The regions correspond to National Electricity Reliability Council regions - the WECC (excluding Canada) is covered by 3 regions in NEMS while MAPP, SPP, and ERCOT are each represented by one NEMS region. The MAPP and SPP regions also include some states outside the WGA region, and we adjust the NEMS results accordingly.

region. We sum the results for each of the 18 states and report them for the WGA region as a whole. This approach yields relatively accurate estimates of generation resources and electric sector operations for the full 18-state region.[43] We did not attempt to precisely assign power plants to individual states. Therefore, we do not present state-by-state results.

C. Results

1. Electricity Use

Table V-4 and Figure V-1 show the electricity consumption levels in each of the scenarios. In the Reference scenario, electricity sales are projected to grow at a rate of about 1.9% per year, rising from 1,013 TWh in 2003 to 1,385 TWh in 2020. In the Current Activities scenario, electricity demand growth is reduced to 1.3% per year on average during 2003-2020. Adopting best practice efficiency policies and programs throughout the region could lower electricity demand growth to only 0.5% per year on average during 2003-2020. In other words, the efficiency activities embodied in the Best Practices scenario (in addition to those in Current Activities scenario) could offset approximately three-quarters of the region's potential growth in electricity sales during 2003-2020.

Figure V-1. Electricity Sales in WGA States, By Scenario

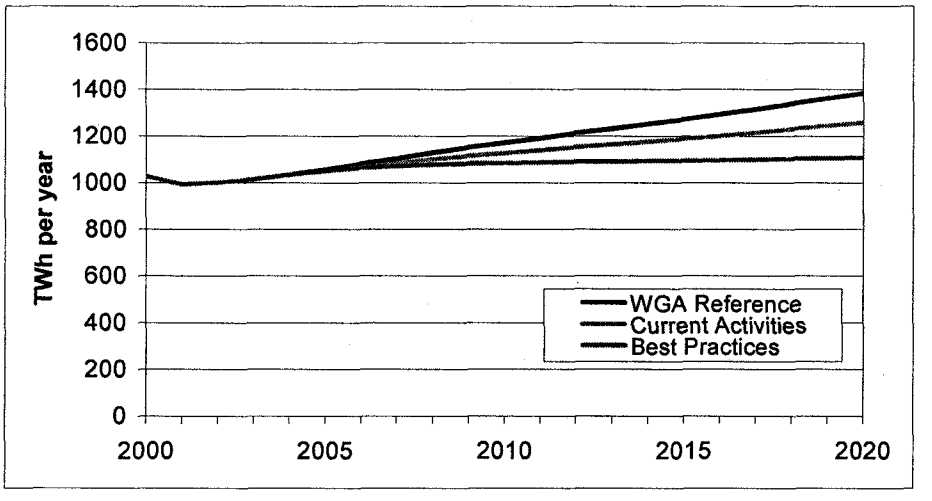


Table V-4 shows that by 2020, electricity sales in the Current Activities scenario are 9% lower than in the Reference scenario. Under the Best Practices scenario, electricity sales in 2020 are 20% lower than in the Reference scenario. Thus, this analysis suggests it is possible to achieve the WGA goal of increasing the efficiency of energy use by 20% by 2020, defined as a 20% or greater reduction in projected electricity use in 2020. Saving 278 TWh in 2020, as is accomplished by the Best Practices scenario, is

[43] Four of the six NEMS electricity supply regions, representing 80-90% of total WGA electricity loads, are fully within the WGA boundaries.

equivalent to the average electricity consumption of about 28 million households[44] or the amount of electricity delivered by 100 large baseload power plants.[45]

Table V-4. Electricity Sales by Scenario (TWh)

	2003	2010	2015	2020
Reference	1013	1171	1273	1385
Current Activities		1126	1188	1258
% change from reference case		-4%	-7%	-9%
Best Practices		1084	1094	1107
% change from reference case		-7%	-14%	-20%

We did not analyze the potential reduction in peak electricity demand from the high efficiency scenarios because the NEMS model does not provide this capability. However, we note that energy efficiency efforts such as utility DSM programs or building energy codes often emphasize measures that reduce peak load such as those aimed at increasing air conditioning efficiency and/or reducing air conditioning load. Therefore, it is likely that the peak demand reduction will be greater than the electricity savings in percentage terms, in both the Current Activities and Best Practices scenarios.

Table V-5 and V-6 show electricity savings in the Current Activities and Best Practices scenarios by program and policy type. In both scenarios, DSM programs contribute about half of overall savings, reducing consumption in 2020 by close to 6% assuming Current Activities and by 12% with Best Practices. As they are already implemented widely in the WGA region (but not accounted for in the NEMS Reference scenario), energy-saving buildings codes also provide significant savings in both scenarios, reducing consumption by over 2% for Current Activities and nearly 4% for Best Practices.

Table V-5. Electricity Savings in Current Activities Scenario, Relative to Reference Scenario (TWh)

Program / Policy type	2005	2010	2015	2020	2010	2020
Appliance Standards	1	**3**	5	**6**	0.3%	0.4%
DSM Programs	4	**26**	50	**76**	2.2%	5.5%
Building Energy Codes	1	**11**	22	**33**	0.9%	2.4%
Market Transformation	0	**2**	4	**6**	0.2%	0.4%
Public Sector	0	**2**	4	**7**	0.2%	0.5%
Total	6	**45**	85	**128**	3.8%	9.2%

[44] Based on average household consumption of 10,000 kWh per year. Note that the electricity savings are from all sectors, not just the residential.

[45] Based on 400 MW plants running at an 85% capacity factor, and delivering electricity with 7% transmission and distribution losses.

Table V-6. Electricity Savings in Best Practices Scenario, Relative to Reference Scenario (TWh)

Program / Policy type	2005	2010	2015	2020	2010	2020
Appliance Standards	1	**7**	13	**20**	0.6%	1.4%
DSM Programs	4	**52**	105	**162**	4.4%	11.7%
Building Energy Codes	1	**16**	34	**54**	1.4%	3.9%
Market Transformation	0	**10**	22	**34**	0.9%	2.5%
Public Sector	0	**3**	5	**8**	0.2%	0.6%
Total	6	**87**	179	**278**	7.4%	20.1%

In contrast, appliance standards and market transformation policies provide more limited savings in the Current Activities scenario, in large part because they are less widely implemented today. Currently only four of the 18 WGA states have adopted appliance standards, and the principal market transformation activities occur in the Pacific Northwest. Savings from appliance standards due to current state activities are also limited due to our representation of the Federal Energy Bill 2005. Since the savings from the appliances covered by the new Federal standards have been included in the reference case, we have avoided double-counting by excluding estimated savings from appliances covered by both state and Federal standards.[46]

The Best Practices scenario assumes that the best existing policies are adopted throughout the WGA region, and as a result, appliance standards and market transformation provide a much more significant contribution to electricity savings. We estimate that widespread adoption of new state appliance standards could reduce regional electricity consumption by 1.4% by 2020, while regional market transformation could reduce consumption by 2.5%.

Programs to promote energy conservation in public buildings are being implemented to some degree in almost all WGA states, but these programs could be strengthened in many cases. The overall savings potential from these programs is relatively low – limited by the fraction of public buildings compared to the full building stock – however they are commonly pursued as a means to demonstrate leadership and provide positive spillover benefits to private buildings.

Each state differs in its contributions to overall electricity savings. By virtue of its large electricity loads and the extent of its efficiency programs and policies, California provides nearly half of the overall electricity savings (62 TWh) in the Current Activities in 2020. In fact, California's electricity savings under the Best Practices scenario for 2020 is not much higher (72 TWh), owing to its already aggressive efficiency efforts. In contrast, Texas provides about one-fifth of the savings in the Current Activities scenario, and with a larger untapped efficiency resource, is the largest source of additional electricity savings in the Best Practices scenario, providing 31% of the total 2020

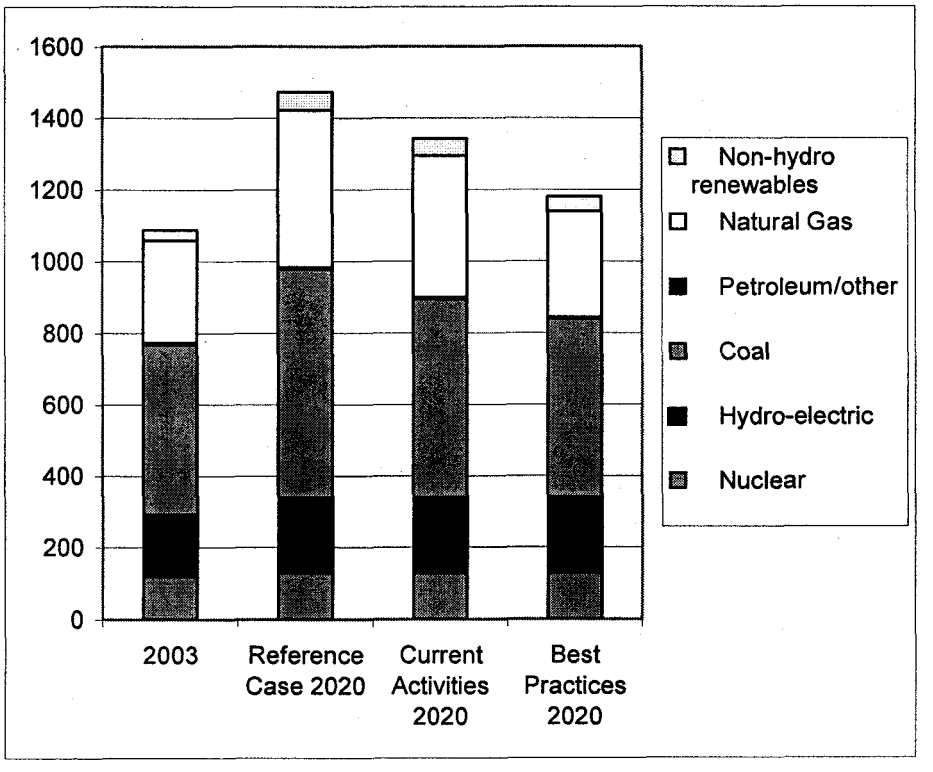
[46] We estimated that the state appliance standards in Arizona, California, Oregon and Washington would have reduced electricity consumption by about 38 TWh in 2020, relative to a reference case without the 2005 federal energy bill.

savings. Owing largely to their smaller levels of state electricity use, no other state contributes more than 10% overall savings in each scenario.

2. Supply Requirements

Currently 70% of the electricity generation for the WGA states is from fossil fuels (coal, natural gas and oil), with nuclear power accounting for about 11%, hydro-electricity for 16%, and non-hydro renewables for 3%. Although many states have policies to promote non-hydro renewables, the modified EIA Reference scenario projects that non-hydro renewable resources increase to only 4% of total electricity generation in 2020.[47]

Figure V-2 Electricity Generation Sources, Current (2003) and Projected (2020), by Scenario (TWh)



With no new large hydro or nuclear power plants expected over the next fifteen years, EIA projects that coal and natural gas plants will provide the vast majority of new generation. The Reference scenario suggests that fossil fuel plants will increase their

[47] Results by specific capacity type are subject to considerable uncertainty, namely because of the many factors that will affect future choices of technology and fuel type, and because results are highly dependent on models and assumptions such as relative fuel prices. In addition, in the case of non-hydro renewables, NEMS is not necessarily up-to-date with respect to the impacts of Renewable Portfolio Standards and other state and local incentives, and thus the results for renewable generation should not be viewed too precisely.

contribution to 74% of total generation in 2020. In this scenario, which embodies EIA's projections for coal and gas prices, two-thirds of new generation will be gas-fired through 2010; thereafter, two-thirds of new generation is projected to be coal-fired as the increasing price of natural gas leads to more reliance on coal-fired plants. Figure V-2 shows the mix of electricity generation in 2003 and 2020, by scenario.

As illustrated in Figures V-3 and V-4 for the Current Activities and Best Practices scenarios, respectively, NEMS modeling suggests that energy efficiency policies and programs will likely avoid electricity generation in a similar pattern – largely displacing gas-fired power in early years, and increasingly displacing coal-fired power during the 2010-2020 period. A small amount of non-hydro renewable energy generation is avoided in the Current Activities and Best Practices scenarios because state Renewable Portfolio Standards would apply to a lower amount of total electricity sales.

Figure V-3. Avoided Generation By Source, 2005-2020, Current Activities Scenario

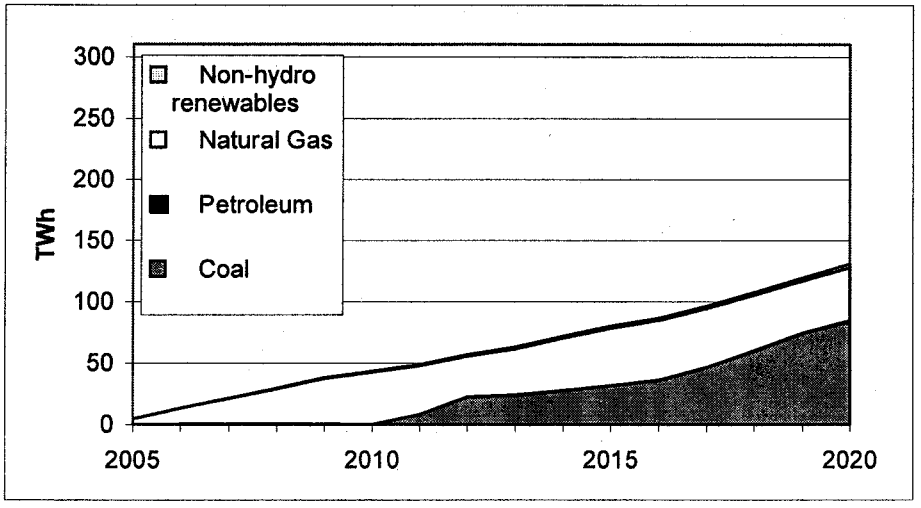


Figure V-4. Avoided Generation By Source, 2005-2020, Best Practices Scenario

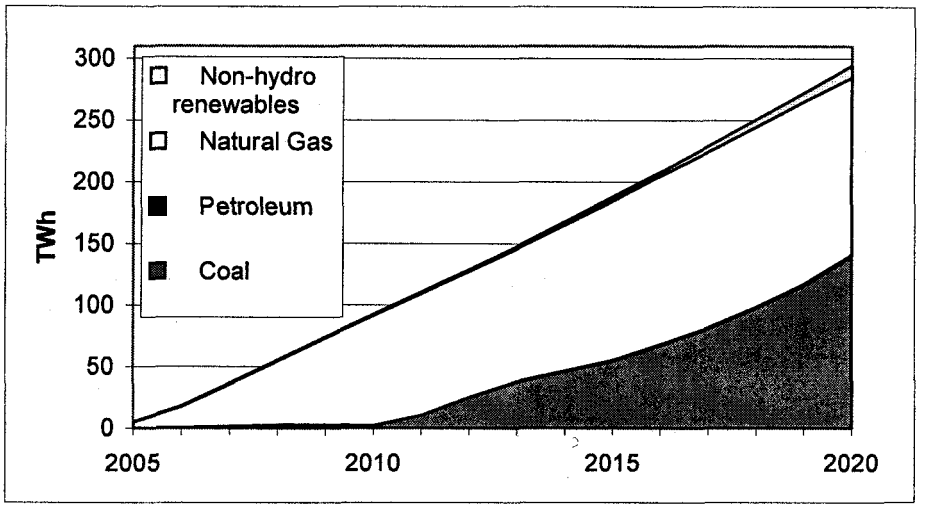


Table V-7 presents the new generating capacity projected for the WGA states for the three scenarios. Relatively few changes occur by 2010 because in the short-run most of the impacts of increased energy efficiency will be less generation from existing power plants, rather than avoiding new power plants. The exception are combustion turbines – about 3GW of new capacity are avoided by 2010 – because this type of power plant has a short lead time and relatively low capital cost, meaning construction levels can be influenced by short term changes in total electricity consumption. By 2020, the results show substantial reductions in construction of both coal and natural gas combined-cycle power plants in the Best Practices scenario. Overall, the modeling indicates 48,000 MW of avoided new generating capacity in moving from the Reference to the Best Practices scenario.

Table V-7. New Electric Power Plant Additions for WGA States

(cumulative GW from 2004)

	2010			2020		
	WGA Reference Case	Current Activities	Best Practices	WGA Reference Case	Current Activities	Best Practices
Coal Steam	*1*	*1*	*1*	*22*	*13*	*6*
Combined Cycle	*12*	*11*	*11*	*31*	*26*	*13*
Combustion Turbine/Diesel	*6*	*6*	*3*	*19*	*12*	*6*
Non-hydro Renewables	*2*	*2*	*2*	*4*	*3*	*2*
Total Capacity	***21***	***19***	***16***	***76***	***54***	***28***

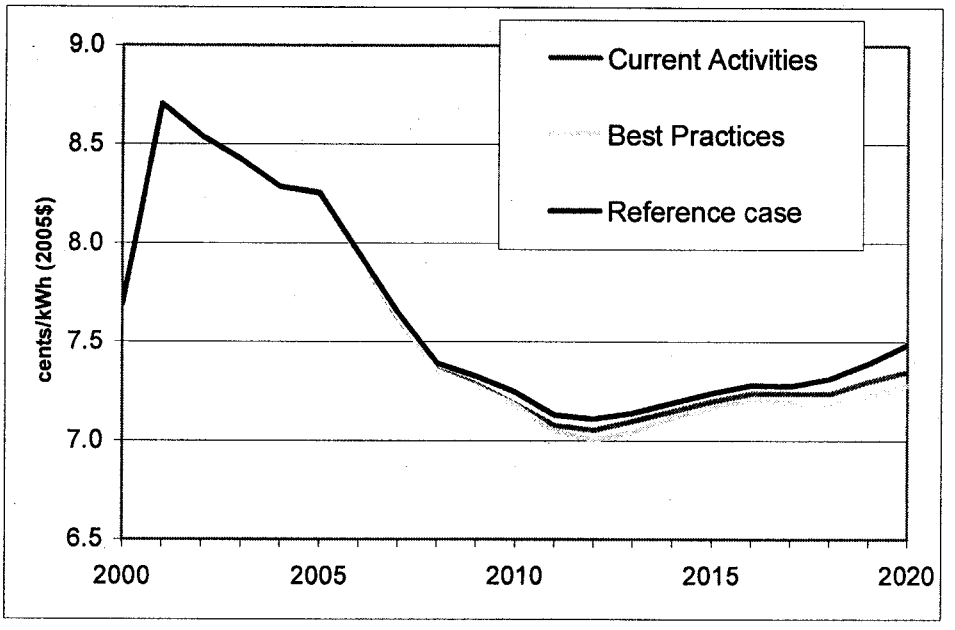
3. Price and Cost Impacts

Under the Reference scenario, average electricity prices (in real dollars) for the WGA states decline from 2005 through 2012 and then begin to rise again, though remaining below 2005 levels through 2020. This overall decline is in large part a product of EIA's assumptions and modeling, which suggest that upward pressures from rising natural gas prices will be countered by expected declines on power plant capital costs and

California's reduced reliance on long-term contracts, particularly in the near-term. With wind generation becoming cost competitive with natural gas in many areas, increased renewable generation due to state policies is projected to lead to little increase in electricity prices.

Figure V-5 illustrates the impact of the energy efficiency policies and programs on electricity prices. Overall, the policies and programs have relatively little impact of electricity on average electricity prices across the region. Average electricity prices in the Current Activities and Best Practices scenarios vary from the Reference scenario by no more than 0.25 cents per kWh in any given year, and in most years the differences are less than 0.1 cent per kWh.

Figure V-5. Electricity Prices, By Scenario



The electricity prices include cost recovery of DSM and market transformation policies. We assume that 50% of the costs of DSM programs and 100% of the costs of market transformation policies will be recovered through increases in rates – these amounts increase electricity prices in 2020 by less than 0.1 cents/kWh in the Current Activities scenario and by 0.2 cents/kWh in the Best Practices scenario. The remaining costs for energy efficiency measures, which we assumed are paid by the individual households and businesses that adopt the measures, are included in the broader economic analysis described below.

Table V-8. Annual Electricity Bill Impacts of Current Activities and Best Practices Scenarios (Billion 2005 dollars)

	2010			2020		
	WGA Reference Case	Current Activities	Best Practices	WGA Reference Case	Current Activities	Best Practices
Residential	**$34**	**$33**	**$31**	**$39**	**$35**	**$30**
% change from reference		*-4%*	*-9%*		*-11%*	*-24%*
Commercial	**$32**	**$30**	**$29**	**$40**	**$35**	**$29**
% change from reference		*-6%*	*-11%*		*-14%*	*-29%*
Industrial	**$17**	**$17**	**$17**	**$19**	**$19**	**$18**
% change from reference		*-2%*	*-3%*		*-4%*	*-9%*
Total	**$84**	**$80**	**$77**	**$99**	**$88**	**$76**
% change from reference		*-4%*	*-8%*		*-11%*	*-23%*

In contrast to the very small impact on electricity prices, energy efficiency policies and programs can have a significant impact on the overall electricity bills paid by consumers of all types. Table V-8 shows the total electricity bill (cost) in 2010 and 2020 for each scenario. The bill reductions are roughly proportional to the electricity savings. In 2020, the Current Activities scenario average electricity bills are 11% lower than in the Reference Case, and in the Best Practices scenario bills are about 23% lower. By 2020, best practice energy efficiency policies and programs could provide residential customers across the 18 states with $9 billion in energy bill savings, commercial customers with $11 billion, and industrial customers with $1 billion.

Table V-9 shows the overall net economic impacts, using a total resource cost and net present value approach. Costs include the incremental capital costs of more efficient technologies plus the program development, implementation and administration costs. Benefits are the avoided costs due to lower electricity generation – decreased costs of building and operating power plants and reductions in transmission and distribution costs. The results show that the benefits of the energy efficiency policies and programs exceed costs by a factor of 2.4 or 2.5, depending on the scenario. The total net economic benefits are $27 billion in the Current Activities scenario and $53 billion in the Best Practices scenario. Once again, this is the cumulative net present value of benefits minus costs from 2005 to 2020. Most of the benefits are due to decreased fuel purchases by utilities and avoided investment in the transmission and distribution grid.

Table V-9. Cumulative Economic Impacts of Current Activities and Best Practices Scenarios, 2005-2020 (Billion 2005$)

	Current Activities	Best Practice
Net economic benefits	**$27**	**$53**
Costs[1]	$19	$35
Benefits (Avoided costs)	$46	$87
generation investment	*$7*	*$13*
fuel	*$13*	*$27*
operating and maintenance	*$5*	*$10*
trans. and distribution investment	*$21*	*$37*
Benefit-Cost Ratio	**2.4**	**2.5**

In fact, these results probably underestimate the net economic benefits of the energy efficiency measures for a number of reasons. First, adopting energy efficiency best practices in western states would have a positive impact outside the region. Downward pressure on natural gas prices in particular should spillover to nearby states, providing some energy bill savings to consumers east of the WGA region. We have not accounted for these potentially substantial (i.e., multi-billion dollar) benefits in the analysis presented here.

Second, the economic analysis is based on EIA's projected natural gas prices as of December 2004. At that time, EIA projected prices to decrease in the early years of the forecast "as drilling levels increase, new production capacity comes on line, and LNG imports increase in response to current high prices" (EIA 2005). EIA then projected increasing prices through 2020, but with wellhead prices remaining under $5 per thousand cubic feet (2005$). However, EIA's most recent short term forecast (September 2005) projects only minor (3%) reductions in the short run, compared with a 12% decline in the EIA AEO2005 reference case for 2005-2006. In fact, natural gas prices were over $10 per thousand cubic feet as of October 2005 in the wake of hurricanes Katrina and Rita, and are expected to remain relatively high due to very tight demand-supply conditions. If natural gas prices remain high and exceed the AEO2005 projections, energy efficiency improvements will result in greater economic benefits than estimated in this analysis.

4. Environmental Impacts

As reported above, active pursuit of energy efficiency opportunities could lead to significant overall cost savings. In addition, the modeling suggests that these energy efficiency gains could result in some environmental benefits as well. As shown in Table V-10, several types of power plants emissions are expected to decline in the Current Activities and Best Practices scenarios, relative to emissions levels in the Reference scenario. Carbon dioxide (CO_2) emissions decline the most, roughly proportional to electricity savings. Nitrogen oxide (NO_X) and mercury emissions decline less significantly, and sulfur dioxide (SO_2) emissions remain constant, looking across the scenarios. SO_2 emissions are subject to an overall emissions cap, as established in the

Clean Air Act, and power plant owners will attempt to meet the cap at lowest cost. So while greater end-use energy efficiency may mean less need for SO_2 emissions reductions by power plants, it does not necessarily lead to a reduction in overall SO_2 emissions.

Table V-10. CO_2, SO_2, NO_x and Mercury Emissions from Power Plants (annual)

		2010			2020		
		WGA Reference Case	Current Activities	Best Practices	WGA Reference Case	Current Activities	Best Practices
CO2 emissions	million metric tons	663	645	632	802	729	664
% change from reference case			*-3%*	*-5%*		*-9%*	*-17%*
SO2 emissions	thousand tons	843	843	843	839	839	839
% change from reference case			*0%*	*0%*		*0%*	*0%*
NOx emissions	thousand tons	901	893	887	970	932	905
% change from reference case			*-1%*	*-2%*		*-4%*	*-7%*
Mercury	tons	10.72	10.72	10.65	10.97	11.00	10.83
% change from reference case			*0%*	*-1%*		*0%*	*-1%*

Electricity efficiency measures also result in a reduction in water consumption. Appliance standards, DSM programs, and other policies lead to more purchase and use of resource-efficient clothes washers, low-flow water spray valves used in commercial kitchens, and other appliances that reduce both water consumption and energy use. In addition, less water would be consumed for power plant cooling if fewer new power plants are needed and less electricity is generated. As shown in Table V-11, we estimate that the Best Practices scenario would save a total of 260 billion gallons of water per year by 2020, equivalent to the water consumption of approximately 1.4 million households.[48] Total water savings during 2005-2020 in this scenario would equal about 1.8 trillion gallons.

Table V-11. Water Savings Relative to the Reference Scenario

(billion gallons per year)

	2010		2020	
	Current Activities	Best Practice	Current Activities	Best Practice
Total	**20**	**49**	**87**	**260**
Demand-side measures	5	18	17	119
Power plants	14	31	70	141

D. Conclusion

The combination of: (a) current state and utility energy efficiency policies and programs, and (b) widespread adoption of "best practice" policies and programs could cut otherwise projected load growth in the western states by about three-quarters during 2003-2020. These efforts would reduce electricity consumption in 2020 by 20% relative to a scenario where both current state and utility activities and best practices are excluded (i.e., the Reference scenario). The absolute electricity savings in 2020 are equivalent to the electricity supply of 100 baseload power plants. Realizing this level of electricity

[48] Based on average annual water consumption of 183,000 gallons per household per year (SWEEP 2002).

savings would enable western states to avoid constructing new power plants that are especially controversial due to their adverse impacts on communities, air quality, visibility, and/or water resources.

Thus we conclude it is possible to achieve the energy efficiency goal enunciated in the WGA Clean and Diversified Energy Resolution, namely realizing 20% electricity savings by 2020. Moreover, even greater savings may be possible through adoption of other strategies not included in our Best Practices scenario, such as expanded R&D, technology transfer, and pricing initiatives.

Implementing best practice energy efficiency policies and programs would provide substantial economic benefits for households and businesses in western states. By 2020, these efforts could lower electricity bills in aggregate by 23%. Furthermore, the Best Practices scenario would yield $53 billion in net economic benefits during 2005-2020 on a net present value basis. The benefits are mostly in the form of avoided fuel purchases by utilities and avoided investment in generation, transmission, and distribution infrastructure.

Implementing best practice energy efficiency policies and programs would also reduce air pollutant emissions. Carbon dioxide (CO_2) emissions would decline the most (17% by 2020) since CO_2 is not currently controlled. In addition, NO_x emissions by power plants would decline a moderate amount (7% by 2020) in the Best Practices scenario, relative to the Reference Scenario.

In addition, energy efficiency best practices would result in water savings from both increased use of energy and water saving devices in homes and businesses, and less operation of steam-based power plants. We estimate that the Best Practices scenario would save 260 billion gallons of water per year by 2020 relative to water use in the Reference scenario, equivalent to the annual water use of about 1.4 million households.

VI. Energy Efficiency Policy Recommendations

This chapter presents the policy recommendations of the Energy Efficiency Task Force. The recommendations are based on our review of best practice policies and programs in the region as well as "what it will take" to achieve the energy efficiency goal in the 2004 WGA energy resolution. We believe that all western states will benefit economically, socially, and environmentally from adopting these recommended policies. However, the priorities and the details concerning policy and program design would no doubt depend on the characteristics and preferences of individual states.

Our recommendations are divided into two categories: (1) state-level initiatives, and (2) regional initiatives. While most of our recommendations pertain to actions that states can take on their own, we believe there are some important opportunities for advancing more efficient use of energy in a coordinated way throughout the region. Our specific recommendations are highlighted in bold type below.

A. State-Level Initiatives

1. Electric Utility Demand-Side Management (DSM) Programs

Leading electric utilities in the country are investing 2-3% of their revenues on DSM programs. These programs in turn save the equivalent of around 0.8-1% of electricity sales each year. This means that these programs cut electricity use approximately 3.5-5% after five years of effort, 8-10% after ten years, etc. As described in Chapter IV, a number of western utilities including Austin Energy, Pacific Gas & Electric Company, PacifiCorp (Utah Power), Puget Sound Energy, San Diego Gas & Electric Co., Seattle City Light, and Southern California Edison are in this category.

The leading utilities are implementing energy efficiency programs for all types of customers and are targeting new construction, equipment replacement, retrofit, and systems improvements including electrical systems in industrial facilities. Successful programs for industrial customers include customer participation in program design, active outreach, flexibility in program participation including an option for "self-direction" of DSM program payments, and thorough monitoring and reporting.

Most western electric utilities are not implementing well-funded, comprehensive energy efficiency and load management programs. It is clear that much more could be done to stimulate the adoption of cost-effective energy efficiency measures in western states. Expanding utility DSM programs would provide economic benefits to customers, help the utilities reduce growth in peak power demand, reduce water consumption for electricity generation, and provide environmental benefits from less fossil fuel consumption by power plants.

DSM programs typically save electricity at a total cost of $0.02-0.03/kWh (utility plus participant costs), meaning that improving end-use efficiency is the least expensive electricity resource. Expressed differently, these programs have a benefit-cost ratio of two

to three (Kushler, York and Witte 2004; NPCC 2005). Also, many DSM programs reduce peak power demand more than they reduce electricity consumption in percentage terms, meaning the programs also improve the load factor for the utility system and improve system reliability.

With adequate measurement and verification, increasing the efficiency of electricity use is also a very reliable and flexible energy resource. **We recommend that all western states require utilities to integrate cost-effective energy efficiency options into resource planning and procurement decisions and pursue energy efficiency whenever it is the least cost resource option. Electricity distribution companies in western states should dedicate at least 2% of revenues to ratepayer-funded energy efficiency programs, assuming that doing so is cost-effective.** These programs are most commonly implemented by utilities, but some states such as Oregon prefer to have the programs implemented by a third party. Funding can be provided either through utility rates, a tariff rider, or separate surcharge commonly known as "public benefits fund."

In addition to ensuring adequate investment levels and measurement and verification processes, the **western states should establish minimum energy savings requirements or targets, either separately or in combination with renewable energy requirements or targets.** In effect this is the policy in Texas where utilities are required to save at least 10% of projected annual load growth through their DSM programs. Also, California has established electricity savings goals for its utilities in order to reduce electricity demand growth by over 50%. **We recommend setting a goal of saving 3-5% of projected electricity sales in 2010 through DSM programs, as long as this is cost-effective. We further recommend setting a goal of saving 10-15% of projected sales from DSM programs by 2020.**[49] This level of savings is consistent with assumed savings from DSM programs in the Best Practices scenario in Chapter V.

In order to stimulate well-funded and effective electric utility energy efficiency programs, it is important to remove financial disincentives that utilities have towards promoting less electricity use by their customers. In this regard, **we recommend decoupling of electricity sales and revenues so that reduced electricity sales do not adversely affect utility revenues and fixed cost recovery, in combination with the creation of performance incentives that reward utilities for implementing effective DSM programs.** These policies have already been adopted in California, Oregon, and other non-western states (Kushler, York and Witte 2004).

As part of DSM program implementation, states should require utilities (or alternative DSM program implementers) to undertake thorough energy savings monitoring and verification, and program cost effectiveness analysis. In particular, utilities should evaluate the net impacts of their programs taking into account both "free riders" and "free drivers" (spillover effect). There are well-established procedures such as the International Performance Measurement and Verification Protocol (IPMVP) and the California Evaluation Framework that states and utilities can use to evaluate energy

[49] To be clear, these recommended savings goals are from cumulative energy efficiency programs starting in 2006.

savings.[50] These functions can be carried out at reasonable cost, without compromising program cost-effectiveness.

2. Gas Utility Demand-Side Management (DSM) Programs

Natural gas prices are high and rising in western states. According to the federal Energy Information Administration, the average residential retail gas price ranged from about $10-17 per million Btu in western states during early summer, 2005. Commercial sector gas prices ranged from about $7-10 per million Btu. Consumers are now paying twice as much for natural gas as compared to a few years ago, and gas prices could be even higher this coming winter.

There is considerable potential to increase the efficiency of natural gas use and do so cost-effectively at today's natural gas prices. A gas energy efficiency potential study completed in Utah showed that well-funded and comprehensive gas DSM programs operated for ten years (2004-2013) could reduce gas use in residential and commercial buildings by 20 percent at the end of this period. Furthermore, the study showed that realizing this gas savings would provide over $1.5 billion in net economic benefits to consumers and businesses in Utah (GDS Associates 2004).

As noted in Chapter IV, some natural gas distribution utilities in western states, such as Southern California Gas Co. and Northwest Natural Gas, sponsor gas conservation programs for their customers. Other gas utilities, such as Southwest Gas Corp. and Public Service of New Mexico, have proposed implementing natural gas conservation programs. These programs include consumer education, marketing, and financial incentives. California recently established minimum gas savings requirements for its utilities, with targeted annual savings increasing significantly during 2005-2010. However, in general, natural gas energy efficiency programs are much less common than electricity efficiency programs.

We recommend that all western states encourage or require gas utilities to integrate energy efficiency resources into their resource planning and procurement decisions and pursue energy efficiency whenever it is the lowest cost resource option. All western states should establish ratepayer-funded natural gas energy efficiency programs. These programs are most commonly implemented by utilities, but as is the case with electricity some states prefer to have the programs implemented by a third party. Funding can be provided through either utility rates, a tariff rider, or a separate surcharge commonly known as a "public benefits charge." **We recommend that gas utilities invest at least 1.5-2% of their revenues in energy efficiency programs, and strive to save the equivalent of 0.5-1.0% of gas consumption per year, as long as this is cost-effective.** These metrics are typical of "best practice" natural gas energy efficiency programs nationwide.

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[50] The IPMVP is available online at www.ipmvp.org. The California Evaluation Framework is available online at www.calmac.org.

In order to stimulate well-funded and effective gas utility energy efficiency programs, it is critical to remove financial disincentives that utilities have towards promoting less gas consumption by their customers. In this regard, **we recommend decoupling of gas utility sales and revenues along with creating performance incentives that reward utilities for implementing effective gas DSM programs.** These policies were recently endorsed by the American Gas Association and Natural Resources Defense Council.[51] In summary, both gas and electric utilities should be rewarded (and not penalized) if they implement effective energy efficiency programs for their customers.

3. Building Energy Codes

Building energy codes specify minimum energy efficiency requirements for new buildings or existing buildings undergoing a major renovation. The eighteen WGA states have differing approaches to building codes: some have mandatory statewide codes with regular upgrade cycles, others are "home rule" states that leave codes up to local jurisdictions.[52] Building codes in the region range from California's totally homegrown Title 24 (with the latest version taking effect in October 2005), to states or cities that have adopted a relatively recent version of the model energy code (the 2003 or 2004 IECC), to states that have outdated codes. They also differ with respect to support for energy code development and education, and achieve different levels of compliance.

Upgrading the energy efficiency of new homes and commercial buildings is very cost effective. A recent study estimated that upgrading the energy efficiency of a typical new home in order to comply with the model energy code in Nevada would cost about $1,500 on average but would result in about $400 in annual energy bill savings, meaning a simple payback of less than four years. Likewise, this study estimated that upgrading the energy efficiency of commercial buildings to comply with the code would cost about $1.60 per square foot but would result in about $0.68 per square foot of energy bill savings per year, meaning a simple payback of about 2.4 years (Geller, Mitchell, and Schlegel 2005).

Well-designed, energy-efficient buildings provide a number of benefits besides energy bill savings. These non-energy benefits include greater comfort, residents that are more satisfied with their new homes, workers in commercial buildings that are more productive, fewer health problems due to indoor air pollutants or mold build-up, and less litigation over building defects (Skumatz and Dickerson 1998; Hall and Roth 2003). Research currently underway at the Harvard School of Public

[51] Environmental Group Teams with Natural Gas Utilities to Promote Innovative State Approach to Energy Efficiency. Joint Statement of the American Gas Association and Natural Resources Defense Council, July 12, 2004. http://www.aga.org/Template.cfm?Section=AGA_News1&template=/ContentManagement/ContentDisplay.cfm&ContentID=14370

[52] Home rule states include Arizona, Colorado, and Texas. Texas passed legislation requiring local governments to follow a single statewide building energy code.

Health is documenting the link between adoption of the latest building energy codes and improved public health due to reduced emissions from power plants.[53]

Training and assisting architects, builders, contractors, and code officials is critical to the successful implementation of new building codes. Studies show that such efforts can significantly improve code compliance (Kinney, Geller, and Ruzzin 2003). Training and technical assistance should be provided in a variety of areas including integrated building design, proper sizing and installation of HVAC systems, proper air tightness and insulation procedures, and use of other state-of-the-art technologies.

We recommend that western states take the following actions in order to realize the energy savings and other benefits offered by state-of-the-art building energy codes:

- **For states with outdated (pre-2003) energy codes, adopt the 2004 International Energy Conservation Code. Also, consider adopting innovative features of California's latest Title 24 building energy codes, such as lighting efficiency requirements in new homes.**
- **All states should update their energy codes regularly. A three-year cycle could be timed to coincide with release of the national model codes.**
- **In home rule states, either establish a statewide mandatory code or strongly encourage local jurisdictions to adopt and maintain state-of-the-art codes.**
- **Implement code training and technical assistance for architects, builders, and local code inspectors. If these support activities are sustained over time, builders, designers, and code officials can become allies rather than opponents of state-of-the-art building codes. Federal funding for this purpose may be available in the future through a provision in the Energy Policy Act of 2005.**
- **Establish a "reach code" for state-owned buildings to demonstrate the feasibility of not only achieving the minimum code requirements but exceeding them. This will encourage the use of advanced energy efficiency products and designs, and will also reward the states with the inherent benefits of more efficient buildings.**

Taking these actions would lead to a high level of energy efficiency in new homes and new commercial buildings, consistent with the assumptions and level of energy savings in the Best Practices scenario in Chapter V. In addition, **we recommend that western states establish a regional building code collaborative**, as explained further in Part B below.

4. Appliance Efficiency Standards

[53] For more information on this research, see http://www.naima.org/pages/resources/library/pdf/NAIMA036.PDF.

The Federal government has adopted minimum energy efficiency standards on a wide range of products including refrigerators, clothes washers, air conditioners, furnaces, water heaters, fluorescent lamps and ballasts, HVAC equipment used in commercial buildings, and motors. But the U.S. Department of Energy is many years behind schedule in its review of existing standards. States are preempted from adopting efficiency standards on products already regulated by the Federal government, but states can adopt efficiency standards on products not covered by the national standards.

Because of this situation, California adopted state standards on 26 products in 2001 and 2004 (see Chapter IV for details). The products include distribution transformers, commercial packaged air conditioning equipment, commercial refrigerators and freezers, commercial clothes washers, icemakers, exit signs, torchiereli ght fixtures, and traffic signals.[54] Other states including Arizona, Oregon, and Washington have copied some of the state appliance efficiency standards adopted by California. These standards are very cost-effective; the energy bill savings pay back any extra first cost in two years or less in most cases (Nadel et al. 2005).

The Energy Policy Act of 2005 includes efficiency standards pioneered by California on 15 different products. **We recommend that California continue to adopt minimum efficiency standards on products not covered by the Federal standards. In addition, we urge other western states to replicate standards first adopted by California, as long as they are cost-effective and not included in Federal standards.** In general, there is little or no opposition to such action, as long as the standards are entirely consistent among states.

5. Public Sector Initiatives

Every western state has taken some action to reduce energy waste in the public sector. Chapter IV summarizes some of the more innovative and successful actions including energy savings requirements for state agencies adopted by Arizona, energy efficiency requirements and goals in California, a successful building retrofit program in Kansas, and a revolving loan fund and retrofit program implemented in Texas. In addition, a number of western states have adopted ENERGY STAR® product procurement requirements.

National policy has established energy savings requirements for Federal agencies and a wide range of energy efficiency initiatives to back them up. The 2005 Federal Energy Act includes new requirements, namely a 2% per year reduction in energy use per square foot in federal buildings during 2006-2015. Western states should follow the lead of the Federal government in this area. **We recommend that all western states adopt "best practices" in public sector energy management including:**

[54] California has the authority to establish and the capability to evaluate appliance efficiency standards through activities of the California Energy Commission. For a summary of the new standards adopted in California, see http://www.energy.ca.gov/releases/2004_releases/2004-12-15_appliances.html.

- **Establish goals for reducing energy intensity by 2% per year or greater in state buildings, track progress towards the goals using a benchmarking system such as the U.S. EPA's Portfolio Manager, and encourage local governments to set similar goals;**
- **Provide financial and technical assistance for implementation of energy savings projects in existing buildings and facilities;**
- **Use energy service companies (ESCOs) and performance contracting to implement efficiency projects without public sector capital investment;**
- **Construct new buildings that are exemplary and surpass minimum energy code requirements by a wide margin; and**
- **Purchase only ENERGY STAR-labeled equipment in categories where such products are designated.**

Adopting these policies should lead to widespread energy efficiency improvements in public buildings, and at least the level of energy savings assumed in the Best Practices scenario in Chapter V.

6. Financial Incentives

There is relatively limited experience with state-funded financial incentives for energy efficiency measures in western states.[55] As noted in Chapter IV, the most extensive incentives are tax credits that the state of Oregon provides for both individuals and businesses that purchase energy efficiency measures. Arizona, Idaho, and Montana have more limited state tax incentives, while the Energy Policy Act of 2005 includes federal tax credits for a variety of residential energy efficiency measures as well as highly efficient new homes and new commercial buildings.

We recommend that other western states consider providing tax incentives to help stimulate greater adoption of energy efficiency measures. In particular, states may want to coordinate qualification levels with the newly adopted federal energy efficiency tax credits. This will enable consumers and businesses to reduce both federal and state taxes when purchasing qualifying energy efficiency measures. Tax credits may be most appealing in states with a budget surplus as well as limited or nonexistent ratepayer-funded energy efficiency programs (e.g., Wyoming). Also, **western states with growing severance tax revenues on fossil fuels production should consider using a portion of these revenues to offset the revenue loss from tax credits on energy efficiency measures.**

7. Pricing and Regulatory Policies

Chapter IV also discusses some of the pricing and regulatory policies that states can adopt to overcome the barriers to greater energy efficiency by consumers and businesses. These policies include decoupling utility revenues from sales and integrating consideration of energy efficiency options into resource planning and procurement decisions.

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[55] This section refers to state-funded incentives rather than ratepayer-funded incentives such as those provided by utility DSM programs.

We recommend that all western states follow the leads of California and Oregon and remove financial disincentives that utilities face if they implement successful energy efficiency programs. As noted above, **we recommend decoupling utility revenues from sales and allowing utilities to keep a small percentage of the net economic benefits produced by their energy efficiency programs.** In order to implement this policy, it is critical to carefully evaluate the energy savings, peak demand reductions, and economic benefits of DSM programs.

Many consumers in western states are used to paying inverted block rates (also known as tiered rates) for water; i.e., the more you consume, the more you pay per unit. A few states including California, Oregon, Utah, and Washington have adopted inverted block rates for electricity (see Chapter IV for details). **We recommend that all western states adopt inverted block rates for electricity consumed by residential customers.** This would provide a price signal that encourages conservation, complementing other policies such as utility rebate programs or building energy codes. **In addition, we suggest that states consider adopting inverted block rates for natural gas.**

8. Education and Training

Consumer, business, and industry education and training are critical components of energy efficiency efforts, in response to the information barriers discussed in Chapter III. Virtually all states implement energy efficiency education and training programs for both households and businesses. In addition, many utility and other ratepayer-funded energy efficiency programs include education and training components.

We recommend continuing and where needed expanding energy efficiency education and training programs at the state, local, and/or regional levels. In particular, we suggest that states:

- **Partner with the U.S. EPA and DOE in promoting ENERGY STAR products, homes, commercial buildings, and industries;**
- **Implement programs to train builders and contractors on proper heating and air conditioning sizing and installation;**
- **Train commercial building energy and facility managers, for example, by making use of the successful building operator training and certification program developed in the Pacific Northwest (Putnam et al. 2002);**
- **Train industrial energy and facility managers in techniques for improving the efficiency of their steam, process heat, pumping, compressed air, motors, and other systems, and partner with the U.S. DOE in doing so; and**
- **Increase awareness of innovative energy efficiency measures such as modern evaporative cooling systems, reflective roofing materials, sealing thermal distribution systems, and use of daylighting.**

The planning horizon for this study, 15 years, provides an opportunity to influence the next generation of energy consumers. Even students who are in kindergarten today

will be making energy purchase and consumption decisions in 2020. Considering how young people have embraced recycling and use of seat belts, **we recommend that K-12 school- and college-based energy education programs be part of this initiative.** Energy education should engage teachers in project-based classroom activities that help students understand the role of energy in their lives and future. Students should be given the opportunity to gain real-world experience in saving energy in schools, homes, and communities, and in advocating for energy efficiency as a cornerstone of protecting the environment (ASE 2004).

9. Technology R&D and Transfer

Many states including California, Texas, and Washington support R&D and technology transfer activities in support of innovative energy efficiency technologies and strategies. In addition, the U.S. DOE supports a number of innovative state-based R&D and technology deployment projects through the State Technologies Advancement Collaborative (STAC). STAC supports projects that involve multiple organizations, in many cases a combination of state energy agencies, universities, and private companies.[56]

Some western states such as Washington are promoting "best practices" in industrial energy management including promoting technologies and strategies developed by the U.S. DOE's Industrial Technologies Program. Specific activities include promoting more efficient motor, compressed air, and steam systems; offering plant assessments; disseminating systems optimization software and other information; and co-funding demonstration projects.[57] **We recommend that all western states initiate, continue, and where appropriate expand programs promoting best practices in industrial energy management.** In doing so, a commitment should be made to deliver targeted training and follow-up technical assistance, to the degree funding permits. In addition, states should encourage companies to set goals for energy efficiency improvement and energy savings, and then track progress towards the goals.

Section 917 of the Energy Policy Act of 2005 authorizes grants to non-profit institutions, state and local governments, or universities, to establish a geographically dispersed network of Advanced Energy Efficiency Technology Transfer Centers. It directs the Secretary of Energy to organize an Advisory Council to provide input to the DOE and to consider the special needs and opportunities for increased energy efficiency for manufactured and site-built housing.

We recommend that western states support energy efficiency R&D and technology transfer activities to increase the commercialization and market penetration of innovative energy efficiency technologies. Governors can urge Congress to appropriate funds for these new programs, and strive to participate if funding is provided. Likewise, more states could participate in collaborative R&D and technology deployment projects such as those co-funded by STAC.

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[56] See http://www.stacenergy.org/about/index.htm for details.

[57] See http://www.eere.energy.gov/industry/technologies/crosscutting_technologies.html for details.

B. Regional Initiatives

States within the WGA region often face similar issues when developing or deploying energy saving and energy efficiency programs. States can form and participate in a regional collaborative to support energy efficiency innovation and enhance delivery of energy efficiency programs. As noted in Chapter IV, the Northwest Energy Efficiency Alliance (NEEA) is a very effective regional organization that is accelerating the deployment of cost-effective efficiency measures in the four northwest states. We recommend that western states consider undertaking the following additional regional initiatives.

1. Creation of Additional Regional Market Transformation Organizations

NEEA is a model organization that other western states should consider replicating. It would be logical to form these organizations for states with strong energy inter-ties and geographical similarities. The following are examples of states and territories that may want to collaborate:

- Arizona, Nevada, New Mexico, and Texas
- Colorado, Utah, and Wyoming
- Kansas, Nebraska, North Dakota, South Dakota
- American Samoa, Guam, Hawaii, and Northern Marianna Islands

We recommend creating additional regional market transformation organizations that would:

- **Promote ENERGY STAR products and programs at the regional level;**
- **Train architects, builders, code officials, and facility managers on energy efficiency practices, codes and compliance options;**
- **Develop and promote voluntary targets or standards for energy efficiency in the commercial and industrial sectors;**
- **Coordinate regionally to train commercial and industrial energy managers, and promote "best practices" in energy management; and**
- **Research, demonstrate and test innovative energy efficiency technologies or strategies.**

Regional collaboration along these lines can provide a number of benefits. States with limited resources can leverage their funds by working with other states and the Federal government. States with similar climates can focus on technologies and programs most effective for their region. And working together at the regional level can be a more effective way to interact with major manufacturers and retailers, compared to working at the state or local level.

2. Building Energy Codes Collaborative

Building energy codes are a critical component for any state energy efficiency program portfolio. As described in Chapter V, building energy codes can provide a considerable amount of electricity savings in the future. But to achieve these savings, codes must be revised periodically and energy code compliance and enforcement must be boosted.

To secure these potential gains and ensure that new construction in the WGA region is reasonably energy efficient, **we recommend forming a regional building energy code collaborative.** This collaborative would consist of code officials, government officials, efficiency advocates, homebuilders, and other stakeholders interested in energy efficiency. **The collaborative could implement the following activities:**

- **Support code development and adoption, including providing analysis of technical and economic viability of innovative code elements. Barriers will be broken down as relationships are developed with builders, designers, and code officials.**
- **Support code implementation through training architects, builders, and code officials at the regional level. In some cases it makes sense to provide this training locally, but in other cases it could be carried out on a regional basis. Also, the regional collaborative could offer to "train the trainers."**
- **Establish a process for code development agencies in the states to coordinate their activities. This will allow states to learn from each other's experiences. It can also be used as an incubator for developing recommendations to submit into the national model code development process, carrying the weight of a considerable block of states and their code officials.**
- **Establish a "reach code" for state- and locally-owned buildings to demonstrate the feasibility of exceeding code requirements. This can be done taking into account climatic characteristics at the regional level.**
- **Support upgrading the HUD manufactured housing energy standards. These homes are outside the scope of state regulation, but they impact energy consumption in the states. Governors should become involved in efforts to upgrade the stringency for this class of homes on the national level.**

This initiative could include a regional effort to secure Federal funding for code adoption and enforcement support. The Energy Policy Act of 2005 contains financial incentives for states that can achieve and document at least a 90 percent rate of compliance with the latest (2004) residential and commercial building energy codes. The Act authorizes (but did not appropriate) up to $25 million per year in incentives for this purpose. Western states can work together to help secure such appropriations for this

program. And if funding becomes available, western states should consider collaborating where appropriate in project development and implementation.

3. Coordinated Appliances Standards Advocacy

Federal minimum efficiency standards on refrigerators, air conditioners, furnaces, water heaters, fluorescent lamps, motors, and other residential and commercial products are very effective. It is estimated that federal standards in effect as of 2001 will save 253 TWh per year of electricity (6.5 percent) by 2010. The standards usually lead to a slight increase in the first cost of new products, but the operating savings exceed any increase in first cost, often by a wide margin. It is estimated that appliance and equipment efficiency standards already enacted will save U.S. consumers over $186 billion net during 1990-2030 (Geller, Kubo and Nadel 2001). Furthermore, appliance standards have not resulted in any loss in consumer amenities or services.

As noted previously, the U.S. Department of Energy (DOE) is responsible for periodically updating the current appliance standards, if this is shown to be technically and economically feasible. However, the U.S. DOE is many years behind schedule in carrying out these rulemakings. In addition, the DOE has the authority to extend federal efficiency standards to products not currently covered by standards, and the U.S. Congress adopted additional standards on 15 products as part of the 2005 national energy bill.

Some individual states such as California and Oregon already urge DOE to establish stronger standards and participate in the rulemakings. **We recommend that western states advocate, as a region, for stronger Federal appliance efficiency standards where this is technically feasible and economically justified.** Advocacy as a region could have a significant impact on the DOE by increasing pressure to speed up the process for updating existing standards and to develop new standards on products not currently covered.

4. Quantification of Air Emissions Benefits

We recommend that western states create or utilize a regional working group to quantify the air emissions benefits of energy efficiency and renewable energy programs and foster inclusion of such programs in state and regional air quality improvement plans. As pointed out in Chapter IV, energy efficiency and renewable energy offer cost-effective opportunities to reduce emissions from the electric sector. These air emissions reductions have the potential to help efforts to reduce regional haze, ozone, and particulate matter.

Several states including Texas have begun to incorporate the emissions benefits associated with specific energy efficiency programs or renewable energy projects into their air quality planning and other regulatory efforts (e.g., administration and evaluation of system benefit charge funds). In recognition of the multiple benefits of energy efficiency and renewable energy, EPA developed policy guidance in August 2004, to

help states incorporate energy efficiency and renewable energy initiatives in their state implementation plans for Clean Air Act compliance (EPA 2004).

There are no cookie cutter approaches to emissions benefit quantification and states have limited resources in this regard. A regional working group would help by providing much needed technical tools as well as information required by policy makers to better integrate energy efficiency and renewable energy into their existing regulatory and policy frameworks. Strategies for implementation of this recommendation include:

- Create a new or use an existing WGA working group to foster and implement this recommendation, or do so through the WRAP;
- Develop new or use existing information to quantify potential emissions reduction benefits in Western States from energy efficiency and renewable energy initiatives;
- Identify a matrix of Federal (e.g., cap & trade) and state regulatory policies (e.g., SIPs, SBCs, RPSs) where inclusion of emissions benefits from energy efficiency and renewable energy efforts bolsters the rationale for adopting these policies; and
- Identify and showcase existing successful state efforts such as the one in Texas and efforts underway or completed in Maryland and Louisiana..

5. Inclusion of Energy Efficiency in Regional Transmission Planning

We recommend that western states collaborate to ensure that the potential for and effects of energy efficiency efforts are incorporated in regional transmission planning. In the past, transmission planning has narrowly focused on paths to connect new central station generation and load centers. There has been little consideration of distributed energy or "negawatts" in the form of customer-based energy efficiency as a means for deferring the need for new transmission lines. However, implementing energy efficiency measures on a large scale can change the shape and size of load and thus the need for new transmission and distribution infrastructure.

To pursue this policy, **we recommend that the WGA convene a regional planning group similar to the New England Demand Response Initiative (NEDRI) or the Mid-Atlantic Demand Response Initiative (MADRI).** The objective of the group would be to ensure that energy efficiency and demand response are integrated into future transmission planning within the WGA region.

NEDRI participants represented about 50 organizations, including state energy and environmental regulators and utilities and energy industry stakeholders. These parties were assisted by professional facilitators and expert consultants. NEDRI produced a consensus report which recommended 11 regional demand response (DR) programs (NEDRI 2003).[58] Recommendations included:

- Strengthening and providing adequate resources and cost recovery, including ratepayer incentives, for regional reliability and economic DR programs;
- Monitoring and limiting the environmental effects of DR programs;

[58] Note that NEDRI defined energy efficiency as long-term demand response.

- Allowing the participation of DR resources in regional ICAP and LICAP markets;
- Adopting performance-based standards for advanced metering and data telemetry systems to facilitate more DR program participation; and
- Supporting the participation of clean distributed generation technologies in regional DR programs.

Billions of dollars are expected to be spent in the West in the next decade on new transmission lines. There is substantial potential for cost savings if energy efficiency is considered in the planning process. However, transmission planners will need to be educated and planning processes modified to promote understanding of the potential impacts from large-scale energy efficiency and DR efforts on transmission systems.

6. Collaboration Among Native American Tribes

The WGA region contains hundreds of small Native American tribes. In many small tribes, there is not sufficient staff to dedicate one or more people to energy issues. Energy management and efficiency duties, if defined, are commonly part of a maintenance position. These staff may not be aware of methods to save or use energy more efficiently. Hiring new staff or dedicating existing staff to energy may be impossible for individual tribes. **We recommend that tribes work together to hire energy management professionals or contractors, train existing staff in energy management, and/or share staff among several tribes.**

Tribes that have similar circumstances, geographic locations or climate would be likely partners. If resources allow, several people with varying skill sets could work as a team and support each other. Tasks of the regional tribal energy efficiency expert or team could include collecting data on existing energy use, conducting energy audits of facilities, developing energy plans, evaluating energy efficiency options, installing energy efficiency equipment, and working with tribal leadership to develop policies to ensure new construction projects are energy-efficient. The energy expert can also work with tribal housing and other government sectors to build efficient new buildings or deploy energy efficiency programs such as weatherization.

Tribes can also leverage their resources by applying for and obtaining federal grants. The Energy Policy Act of 2005 directs the Secretary of the Department of Housing and Urban Development to promote energy efficiency in housing that is located on Native American land.

7. Reducing Barriers to Performance Contracting and Other Strategies for Increasing Energy Efficiency in Commercial Buildings

The energy efficiency potential studies reviewed in Chapter II showed there is tremendous potential to save energy in commercial buildings. Retrofitting commercial buildings with energy efficient equipment (e.g., insulation, lighting, HVAC) and "tuning up" energy management and control systems can dramatically reduce energy usage (and

costs) and improve occupant comfort and building function. Performance contracting is an effective method to improve the commercial building stock, however barriers exist.

We recommend forming a working group that would develop a set of recommendations to overcome the barriers to implementing greater energy efficiency in commercial and public buildings, barriers such as financial impediments, lack of knowledge and information on energy efficiency benefits, and building ownership structures. The working group could include representatives of commercial building owners, state and local government facility managers, energy project finance companies, energy service companies, state energy offices, and U.S. DOE and U.S. EPA. **Among the strategies the working group should consider, we suggest:**

- **Setting energy savings targets for existing commercial buildings;**
- **Promoting benchmarking using guidelines developed by the U.S. EPA and refined by California;**
- **Setting up building commissioning and retro-commissioning programs patterned after those operating in California, Texas, and Utah; and**
- **Adopting mechanisms that will increase performance contracting by both the private and public sectors.**

A precedent for this effort is the Green Building Initiative (GBI) convened by the Governor of California and chaired by a prominent California real estate developer. This initiative resulted in an Executive Order and Action Plan that emphasizes the increased use of performance contracting and benchmarking in one million commercial and government buildings.[59]

[59] See http://www.energy.ca.gov/greenbuilding/index.html for further details.

VII. Conclusion

Increasing energy efficiency is our cleanest, cheapest, least risky, and least controversial energy resource. Energy efficiency should be a major component of energy strategies developed and implemented by Western Governors at the state and regional levels. Some western states have already undertaken important initiatives including adopting comprehensive and well-funded utility energy efficiency programs, up-to-date building energy codes and/or appliance efficiency standards, initiatives to improve energy efficiency in the public sector, tax credits, and R&D and technology transfer efforts. In addition, the Pacific Northwest states have formed a model organization aimed at transforming energy efficiency markets at the regional level. But much more can and should be done.

Adopting "best practice" energy efficiency policies and programs in all western states could eliminate most of projected load growth during 2005-2020, reduce overall electricity consumption in 2020 by 20% relative to a scenario without energy efficiency initiatives, and yield tremendous economic and environmental benefits. We estimate that consumers and businesses in the region would save over $50 billion net during 2005-2020 if best practices in energy efficiency policies and programs are widely implemented. Doing so would also save approximately 1.8 trillion gallons of water, substantially reduce power plant CO_2 emissions, and moderately reduce NOx emissions.

In order to realize these broad benefits, we recommend that Western Governors work with their legislatures, state regulatory commissions, and private sectors to enact new policies aimed at increasing the efficiency of both electricity and natural gas use. There is no "silver bullet" for overcoming the barriers that are inhibiting widespread energy efficiency improvements. But there are a variety of proven policies and programs that are available for states to take advantage of. With energy costs high and rising, the time to act is now.

States that adopt a combination of financial incentives, education and training programs, R&D and technology transfer efforts, energy efficiency requirements, and integrated energy planning will advance the furthest in developing their energy efficiency resources. In addition, western states could benefit from increased cooperation in the development, analysis, and deployment of cost-effective energy efficiency policies and measures.

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Appendix B – Analytical Approach

Our approach for this analysis consists of estimating electricity demand reductions and investment costs due to electricity efficiency based on recent analysis from Western U.S. sources. These electricity demand reductions were analyzed within the National Energy

Modeling System (NEMS) to simulate the response in the electric sector (avoided costs, avoided emissions, incremental power supply costs, supply/demand/price feedback effects, etc.).

NEMS is the primary energy forecasting and policy analysis model developed and used by the Energy Information Administration (a branch of the U.S. Department of Energy). The electricity market module (EMM) of NEMS models electricity demand/supply interactions by dividing the United States into 13 National Electricity Reliability Council (NERC) regions, some of which embody or approximate power pools (see Figure B-2). The model ensures that supplies are developed and dispatched to meet the demands in each region, taking account of system reliability, the capital, fuel and O&M costs of new power plant options (see Table B-1), the operating costs of existing units, the efficiencies and outage rates of all power plants, transmission and distribution system costs and losses, inter-regional sales and purchases, state renewable energy requirements, and national and regional pollution cap and trade systems. Prices for fuels used in the electric sector (natural gas, coal, biomass, fuel oil) are determined endogenously – depending on demand for these fuels. NEMS is able to capture the benefits of lower electricity demand leading to lower natural gas demand, which results in lower natural gas prices for all users.

NEMS EMM provides information on:

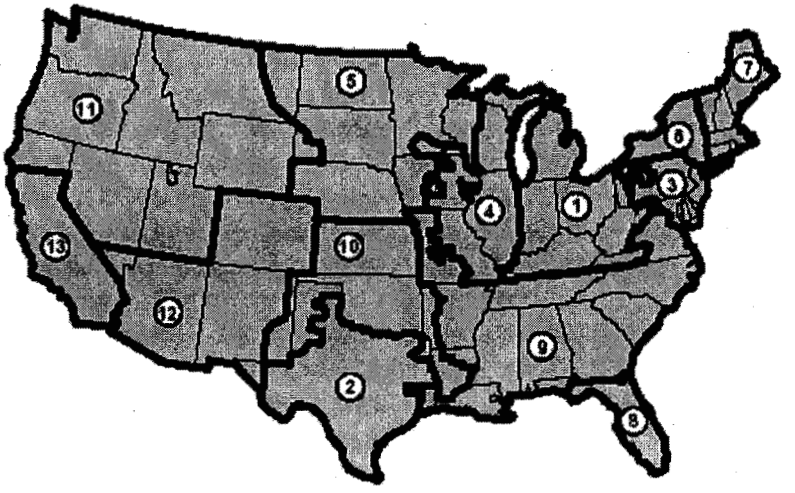
- Amount and type of electricity generation, including non-utility generation, fuel use, imports and exports;
- SO_2, NO_X, mercury, and CO_2 emissions; and
- Costs for new capital investments, fuel and operations, transmission and distribution.

NEMS also has individual modules for the residential, commercial and industrial sectors. We did not use these modules directly in our analysis, but we did use the output of the modules as a starting point for the electricity sales projections by state (see state-level projections section below). These modules use Census Divisions (see Figure B-2) to represent U.S. regions.

The NEMS analyses were used to determine costs and emission reductions by comparing a reference case scenario with the scenarios containing the electricity sales reductions (owing to greater end-use efficiency).

Further information on NEMS is available from the Energy Information Administration's website, www.eia.doe.gov/bookshelf/docs.html.

Figure B-1. Electricity Market Module regions in NEMS



1 East Central Area Reliability Coordination Agreement
2 Electric Reliability Council of Texas
3 Mid-Atlantic Area Council
4 Mid-America Interconnected Network
5 Mid-Continent Area Power Pool
6 New York
7 New England
8 Florida Reliability Coordinating Council
9 Southeastern Electric Reliability Council
10 Southwest Power Pool
11 Northwest Power Pool
12 Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada
13 California

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

Figure B-2. U.S. Census Divisions in NEMS

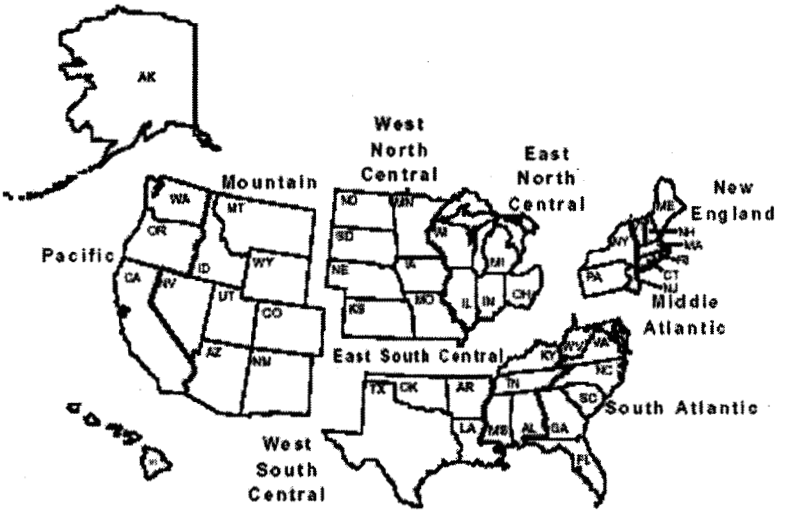


Table B-1. Power Plant Assumptions in NEMS

	Conventional Coal	Coal (IGCC)	Natural Gas Combined Cycle - conventional	Natural Gas Combined Cycle - advanced	Natural Gas Combustion Turbine - conv	Natural Gas Combustion Turbine - advanced
Capital Cost (2005$/kW)						
installed 2005-2011	1,226	1,473	600	589	419	394
installed 2012-2018	1,204	1,405	590	552	412	358
installed 2019-2025	1,174	1,272	580	525	404	331
Capacity factor (%)	85	85	87	87	10	10
Fixed O&M ($/kW-yr.)	25	35	11	10	11	9
Variable costs (incl fuel) ($/MWh)						
2008	13	11	44	41	67	55
2015	15	13	45	42	69	57
2022	17	14	49	45	75	62
Typical Size (MW)	*600*	*550*	*250*	*400*	*160*	*230*
Estimate of total cost (2005$/MWh), total resource cost perspective						
installed 2005-2011	27	28	50	47	110	95
installed 2012-2018	29	29	51	48	112	94
installed 2019-2025	31	30	55	51	118	97
CO2/MWh						
installed 2015	0.813	0.681	0.370	0.335	0.552	0.451

	Biomass	Landfill Gas - High Yield	Landfill Gas - Low Yield	Landfill Gas - Very Low Yield	Wind	Solar PV (central station)	Solar Thermal
Capital Cost (2005$/kW)							
installed 2005-2011	1,836	1,459	1,843	2,831	1,193	3,911	2,596
installed 2012-2018	1,744	1,442	1,822	2,797	1,191	3,322	2,415
installed 2019-2025	1,583	1,426	1,801	2,766	1,187	2,900	2,227
Capacity factor (%)	77	80	80	80	32-34	25	22
Fixed O&M ($/kW-yr.)	48	100	131	212	27	10	51
Variable costs (incl fuel) ($/MWh)							
2008	10	13	13	13	0	0	0
2015	16	15	15	15	0	0	0
2022	17	18	18	18	0	0	0
Typical Size (MW)	*100*	*30*	*30*	*30*	*50*	*5*	*100*
Estimate of total cost (2005$/MWh), total resource cost perspective							
installed 2005-2011	35	41	49	70	36	121	114
installed 2012-2018	40	43	51	71	36	103	108
installed 2019-2025	40	45	53	74	36	91	102

Source : EIA 2005, Tellus Calculations.

Reference Case Modifications

The primary modifications that we made to the EIA reference case were to include the estimated energy savings from (1) the 2005 Federal Energy Bill and (2) EPA's ENERGY STAR programs. The 2005 Federal Energy Bill was passed in August 2005, after EIA had prepared the AEO2005 reference case. We used estimates provided by the American Council for an Energy-Efficient Economy for national savings in 2010 and 2020 (ACEEE 2005), as shown in Table B-2. We interpolated the values between years and used a feature in NEMS to allocate savings pro-rata to each region. These electricity savings reflect a 4% reduction of national electricity consumption in 2020.

Table B-2. Savings from 2005 Federal Energy Bill, national (TWh)

	2010	2020
Appliance Efficiency Standards	21	90
Tax Incentives	4	22
CHP	11	30
RD&D	2	12
Miscellaneous	19	45
Building Energy Codes	0	3
Public Awareness	6	4
TOTAL	**63**	**206**

Source: ACEEE 2005 staff report

Discussions with EIA and EPA staff along with review of NEMS input assumptions and detailed output indicated that the EIA reference case accounts for many federal energy efficiency programs (such as the minimum energy efficiency standards for equipment stated in the Energy Policy Act of 1992, updated in 2003). However, the EPA's ENERGY STAR program is not completely represented in the model. EPA staff provided the expected national energy savings from ENERGY STAR residential electronics and office equipment.[60]

Another modification to the EIA reference case was the planned reserve margins for each EMM region. The reserve margin is used to plan the amount of new capacity, based on expected future levels of peak demand. In NEMS, each EMM region is assigned a minimum reserve margin and the model ensures that sufficient capacity is built to meet this margin. In order to represent time delays, NEMS includes required lead times for building new power plants of 2-6 years and it includes foresight on expected future peak demand. The planning reserve margin is used to determine the set of builds that must be started in one year to meet peak demands in future years with an overall goal of lowest system costs. The planning reserve margins currently in NEMS are based on a review several years ago of WECC and NERC data. We compared the reserve margins in NEMS with current levels of reserve margins in the western EMM regions and with the plans provided by WECC, ERCOT, and NERC sources (WECC 2005, ERCOT 2005, NERC 2004). We found that the reserve margin implied or reported in the recent NERC reports

[60] We assume that the energy savings effects from other ENERGY STAR products are captured to a substantial degree through the utility DSM programs underway or proposed for the region.

were higher than the reserve margins in NEMS. Further discussions with EE task force members and other electric sector industry contacts indicated that the levels of new builds included in the recent NERC reports may under-estimate the impacts of contributions by independent power producers and over-estimate the likely amount of new capacity requirements. To account for the higher estimates from the recent NERC reports, yet avoid over-estimating builds, we chose the mid-point between current NEMS reserve margins and the amounts from the recent NERC reports, as shown in Table B-.

Table B-3. Reserve Margins, Original NEMS Values, Values Implied By NERC Reports, Final Values Input for Reference Case (and all other scenarios)

	NEMS values	implied by current NERC reports	**Modified values**
ERCOT	17%	20%	**19%**
MAPP	6%	13%	**10%**
SPP	10%	12%	**12%**
NWP	18%	48%	**33%**
Rocky mountain	16%	30%	**23%**
California	17%	31%	**24%**

State-level Projections

In order to estimate the impact of a variety of energy efficiency policies and programs, it was necessary to estimate future electricity sales for each of the WGA states. Since we did not find a readily available, consistent source of state-level electricity projections, we relied on the projection embodied in the NEMS AEO2005 reference case. The AEO2005 reference case provides electricity sales projections by census division (see Figure B-2). We applied the census division annual electricity growth rate, by sector, to each state in the division. These are rough estimates and will not accurately capture differences between states in each division. However, they provide a starting point for the analysis, and since the focus of the analysis is on electricity which is supplied on a regional basis rather than by individual states, the impact of this generalized approach is expected to be small in terms of the final results.

EXHIBIT

APS-41
admitted

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF

WILLIAM E. AVERA

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

DIRECT TESTIMONY OF WILLIAM E. AVERA

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DIRECT TESTIMONY OF WILLIAM E. AVERA

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)

I. INTRODUCTION

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. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Appendix A.

A. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Arizona Corporation Commission ("ACC" or the "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 "the Company"). In addition, I also examined the reasonableness of APS' requested capital structure, considering both the specific risks faced by APS and other industry guidelines

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS HEARING.

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. In connection with the present filing, I considered and relied upon corporate disclosures and management discussions, 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 investors' requirements for APS as it competes to attract capital, and they form the basis of my analyses and conclusions.

Q. WHAT IS THE ROLE OF THE COST OF CAPITAL IN SETTING A UTILITY'S RATES?

A. The cost of capital 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 allowed cost of capital should be sufficient to (1) fairly compensate the utility's capital investors, (2)

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first reviewed the operations and finances of APS and the general conditions in the electric utility industry and the economy. With this as a background, I developed the principles underlying the cost of equity concept and then conducted various quantitative analyses to estimate the cost of equity for a group of reference utilities. These included discounted cash flow ("DCF") analyses, risk premium methods encompassing alternative approaches and studies, and reference to comparable earned rates of return expected for utilities and industrial firms. From the cost of equity range indicated by my analyses, a fair rate of return on equity was selected taking into account the economic requirements and specific risks and potential challenges for APS, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity for the Company's jurisdictional electric utility operations in Arizona.

B. 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 of 11.5%. The bases for my conclusion are summarized below:

- Considering investors' expectations for capital markets, the substantial funding requirements faced by APS, and the need to support financial integrity and fund crucial capital investment even

under adverse circumstances, it is my opinion that 11.5% is a reasonable ROE for APS. Specifically, I concluded that:

- Applications of alternative quantitative methods to a proxy group of other electric utilities operating in the Western U.S. implied a cost of equity range of 10.8% to 11.8%, before considering an allowance for flotation costs;
- Expectations for higher interest rates should be considered in establishing a fair rate of return for APS;
- Incorporating a 20 basis-point allowance for equity flotation costs resulted in a fair rate of return range for the electric utility proxy group of 11.0% to 12.0%; and
- Based on the midpoint of this range, 11.5% represents a reasonable rate of return on common equity for APS.

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 55% 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 expectations for the electric utilities in the proxy group used to estimate the cost of equity;

- Regulatory support for higher equity levels is necessary to support 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:

- Considering investors' heightened awareness of the risks associated with the electric power industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation is perhaps more crucial now than at any time in the recent past;
- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity;
- APS must compete for investors' capital with other utilities and businesses of comparable risk. Standard & Poor's Corporation ("S&P's") corporate credit rating for APS falls at the bottom of the range for the proxy group and represents the lowest rating on the investment grade scale. If APS 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;
- Ultimately, it is customers and the service area economy that benefit when the utility has the opportunity to maintain the financial wherewithal that is necessary, not just to maintain short-term liquidity, but to take actions to provide an efficient, reliable energy

supply over the long-term.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of APS. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are 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. As of December 31, 2004, APS had total assets of approximately $8.1 billion, with operating revenues totaling approximately $2.2 billion.

The Company's retail electric operations are subject to the jurisdiction of the ACC, with transmission operations being regulated by the Federal Energy Regulatory Commission ("FERC"). Additionally, APS' nuclear facilities are subject to licensing and oversight by the Nuclear Regulatory Commission ("NRC"). State

legislation has significantly restructured the electric utility industry in Arizona. Under the Retail Electric Competition Rules approved by the ACC,[3] retail access became available to all APS retail electricity customers effective January 1, 2001 and Arizona utilities were required to unbundle rates for noncompetitive services. In addition, all competitive electric assets and services were to be sold to an unaffiliated party or transferred to a separate corporate affiliate.

In the wake of the Western energy crisis in 2000-2001, however, the ACC effectively halted restructuring to review its policies. In September 2002, the ACC issued the "Track A" Order, which reversed the requirement to transfer competitive assets and directed APS to cancel its transfer of generation assets to PWEC. In March 2003, the ACC issued its "Track B" Order, which required investor-owned utilities subject to its jurisdiction to solicit competitive bids for certain estimated capacity and energy requirements beginning July 2003. More recently, the ACC affirmed the Company's ability to build and acquire generation to meet its native load requirements and authorized the transfer of approximately 1,800 Megawatts ("MW") of generating capacity built by PWEC in Arizona to APS. Currently, APS is prohibited from building new generating capacity through January 1, 2015, unless adequate power supply cannot be obtained in the wholesale market at reasonable cost.

The regulatory developments and challenges surrounding the Retail Electric Competition Rules have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000,

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[3] A.A.C. R14-2-1601.

there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers.

Q. PLEASE DESCRIBE APS' ELECTRIC UTILITY OPERATIONS.

A. APS employs about 6,100 individuals, with energy sales amounting to over 57.2 million megawatt ("MW") hours during 2004. Approximately 50% of 2004 retail electric revenues were attributable to residential customers, with 42% from commercial and 8% from industrial and other users. The Company's generating facilities include its 29.1% interest in the three nuclear units of the Palo Verde Nuclear Generating Station ("Palo Verde"), with a total capacity of approximately 1,107 MW. In 2004, nuclear generation accounted for approximately 14% of the electric energy provided by APS, with coal at 21%, and natural gas at 2%.

In addition to its own generating capacity, APS relied on purchased power arrangements for the remaining 63% of its 2004 energy needs.[4] One of the most important of APS' purchase power agreements is a long-term contract with Salt River Project. The generating capacity available to APS pursuant to the contract is 350 MW, which will be reduced to 150 MW in 2007.

APS' transmission and distribution facilities consist of approximately 17,800 pole miles of overhead lines and approximately 13,764 miles of underground lines. Along with other owners of electric transmission lines in the southwestern U.S., APS has been participating in the evaluation of a proposal that would satisfy the FERC's requirements for the formation of a Regional Transmission Organization ("RTO"). At December 31, 2004, APS' investment in net utility plant was approximately $6.3 billion.

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[4] Includes energy attributable to the PWEC generating facilities that were transferred to APS in 2005.

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 the second-fastest growing region in the U.S. (behind Las Vegas), and the Company anticipates continued expansion on the order of 3% annually, with demand expected to increase on the order of 5,000 MW over the next ten years. In order to keep pace with customer growth and enhance utility infrastructure, APS anticipates construction expenditures of approximately $1.2 billion for 2005 and 2006 alone.[5] 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. Beginning April 1, 2005, APS implemented a power supply adjuster ("PSA") for recovery of variations in purchased power and fuel costs. Under the PSA, actual costs for purchased power and fuel are compared with the amount included in retail base rates and, subject to certain limits and restrictions, differences will be deferred for future recovery or refund. The PSA provides for an incentive mechanism where APS and its customers share 10% and 90%, respectively, in any higher costs or savings. The implicit assumption of such a mechanism is, of course, that management has some limited means to influence these costs.

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[5] Pinnacle West Capital Corporation, Form 10-Q Report (June 30, 2005) at 49.

Under the PSA, annual changes in the adjustor are limited to plus or minus $0.004 per kilowatt hour ("kWh"), with additional amounts being recorded in a balancing account. Subject to ACC approval, a surcharge is possible if the balancing account reaches $50 million, with APS filing its first request to implement an adjustor surcharge under the PSA on July 22, 2005.[6] The PSA provides that the Commission or ACC 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.

Q. WHAT CREDIT RATINGS HAVE BEEN ASSIGNED TO APS?

A. Citing increased regulatory and operating risks related to growing balances of deferred fuel and power costs, on December 21, 2005 Standard & Poor's Corporation ("S&P") lowered the corporate credit ratings of APS and Pinnacle West from "BBB" to "BBB-".[7] While Moody's Investors Service ("Moody's) and Fitch Ratings ("Fitch") have at the time of the filing maintained their long-term credit ratings of Baa1 and BBB respectively, for APS, both agencies have placed the Company under review for a possible downgrade.[8]

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[6] Docket No. 0E-1345A-03-0437 and 0E-1345A-05-0526.

[7] Standard & Poor's Corporation, "Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered to 'BBB-'; Outlook Stable," *RatingsDirect* (Dec. 21, 2005).

[8] Moody's Investors Service, "Rating Action: Arizona Public Service Company," *Credit Research* (Jan. 10, 2006); Fitch Ratings Ltd., "Fitch Places PNW and APS on Rating Watch Negative" (Jan. 6, 2006).

B. Electric Utility Industry

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

A. Over the past decade, the industry has experienced significant structural change resulting from market forces and decontrol initiatives. At least initially, this process was largely driven by regulatory reforms at the federal level. The national Energy Policy Act of 1992 greatly increased prospective competition for the production and sale of power at the wholesale level, with FERC being an aggressive proponent for actions designed to foster greater competition in markets for wholesale power supply.

Most market observers agree that, while "open access" to FERC-jurisdictional transmission facilities has resulted in more competition in wholesale energy markets, it has also introduced substantial risks – particularly for utilities (like APS) that depend on wholesale markets for a portion of their resource requirements.

Q. WHAT IMPACT DID THE WESTERN POWER CRISIS HAVE ON INVESTORS' RISK PERCEPTIONS FOR FIRMS INVOLVED IN THE ELECTRIC POWER INDUSTRY?

A. Events of the last several years caused investors to rethink their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis throughout the West wreaked havoc on the customers, utilities, and policymakers. It also had dramatic repercussions for wholesale power markets and investors and utilities nationwide. In many states -- including Arizona -- regulators and legislators placed restructuring initiatives for the retail sector of the electric industry on hold as the financial implications of the Western energy crisis brought the uncertainties associated with today's power markets into sharp focus for the

investment community and other stakeholders. While the case of California represents an extreme example, there is every indication that investors' risk perceptions for all electric utilities shifted sharply upward in response to these events.

Q. HOW WERE WESTERN UTILITIES IMPACTED BY CONDITIONS IN THE ELECTRIC POWER INDUSTRY?

A. The financial integrity of many utilities in the region was severely damaged by the maelstrom of the Western energy crisis. While a full description of the Western power crisis and its effects is beyond the scope of this testimony, the chaotic market conditions were felt directly and with full force. S&P cited the debilitating impact of these developments on investors' willingness to provide capital and recognized that the end result of investors' waning confidence in the industry was reduced access to capital.[9]

Utilities were forced to use cash flows from operations, various bank borrowings, and short- and long-term debt to fund unrecovered energy supply costs. This led to a sharp deterioration in financial condition, a severe liquidity crunch, and a dramatic increase in credit risk. As a result, commercial banks were highly reticent to extend financing for ongoing operations or new construction and counterparties involved in meeting the utilities' energy needs became unwilling to transact business absent special credit terms. To varying degrees, utilities throughout the western U.S. were confronted with the difficult task of maintaining reliable service and financial integrity in a power market characterized by short supply and unprecedented price volatility. As a result, investors recognize that volatile markets

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[9] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).

and inopportune reliance on wholesale purchases to meet resource needs can constitute a dangerous combination, exposing the utility to the risk of reduced cash flows and unrecovered power supply costs.

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

A. Yes. The last several years 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 15 upgrades,[10] while Moody's downgraded 109 utility issuers and upgraded 3.[11] Credit quality continued to decline during 2003, with S&P reporting that downgrades outpaced upgrades by more than 15 to one in the fourth quarter of 2003.[12] While the pace and scale of negative ratings actions has since diminished, 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 THERE ANY INDICATION THAT THE IMPORTANCE OF THESE CONSIDERATIONS HAS DIMINISHED IN THE EYES OF INVESTORS?

A. No. Investors recognize that the continuing prospect of further turmoil in Western energy markets cannot be discounted, with S&P reporting continued spikes in wholesale market prices in the aftermath of the crisis:

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[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. Utility Upgrades Beat Downgrades In Second Quarter, But Negative Watch Listings Grew," *RatingsDirect* (Jul. 28, 2005).

> For 2003, record-high wholesale power prices were the defining feature of the U.S. merchant power markets. ...Power prices across the U.S. continent generally rose on the order of 50% or more in 2003. ...Prices in the western regions were also the highest on record outside of the 2000-2001 California energy crisis.[14]

More recently, S&P concluded that, while the severe distortions that characterized the energy crisis of 2000-2001 have faded, "[n]atural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development" are "daily reminders" of the challenges to the financial health of Western utilities.[15] Meanwhile, the FERC Staff has warned of the ongoing potential for market disruption in the West, as a recent report concluded:

> Our review of supply and demand conditions in the west this summer indicates that there may be periods of market tightness most likely expressed as price spikes and possible interruptions.[16]

Additionally, 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.[17] S&P noted the danger posed by "high and volatile natural gas prices," which increase the uncertainties associated with power supply costs.[18] As the

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[14] Standard & Poor's Corporation, "Energy Commodity Report: U.S. Power Prices Record High in 2003," *RatingsDirect* (Jan. 15, 2004).

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

[16] Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, "Summer Energy Market Assessment 2005," (May 4, 2005) at 9.

[17] For example, the Energy Information Administration ("EIA") reported that the average spot gas price at the Henry Hub spiked to $18.85 per MMBtu in February 2003, before declining to approximately $5.00. More recently, EIA noted that "prices at the Henry Hub on Wednesday, October 12 exceeded last year's level by $8.36 per MMBtu or about 156 percent." (*Natural Gas Weekly Update,* Mar. 27, 2003 and Oct. 13, 2005).

[18] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005)

Economist Intelligence Unit, Ltd. indicated, this sensitivity has only been magnified by fallout of the natural disaster in the Gulf Coast region:

> Hurricane Katrina has sent gas prices to new record levels, exacerbating an already supply-tight market that has seen high prices for the last two years. There is little indication that the situation will improve in 2006...[19]

Similarly, ACC Chairman Jeff Hatch-Miller warned Arizona consumers to prepare for the future in light of the "meteoric rise" in the cost of natural gas.[20]

In addition, while coal has historically been a relatively stable source of fuel, rising prices 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.[21]

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

A. No. While approval of the PSA was a positive step and supportive of the Company's financial integrity, it does not apply to 100% 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. Citing the example of a gas utility, S&P observed that:

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[19] Economist Intelligence Unit, Ltd., "World Commodities – Natural gas market outlook," (Sep. 1, 2005) at 1.

[20] Arizona Corporation Commission, "Natural Gas Forum: What Utilities & Consumer Groups are Doing to Prepare Customers for the Winter Ahead," *News Releases* (Sep. 1, 2005).

[21] Standard & Poor's Corporation, "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," *RatingsDirect* (Aug. 12, 2004).

> Slow recovery could impinge on the firm's liquidity as short-term funds are consumed to finance high-cost gas purchases. In turn, this may necessitate a large bank line that increases borrowing costs.[22]

In the case of APS, the PSA applies to 90% of the deviation between actual power supply costs and normalized rates. In addition, annual changes in the adjustor are limited to $0.004 per kWh lifetime cap, with additional amounts being deferred to a balancing account. A surcharge to address such deferrals is only possible when the balancing account reaches $50 million, and then only with ACC approval. Under the PSA, the total amount of annual fuel and purchased power costs that APS may recoup was capped at $776.2 million. Thus, in addition to absorbing 10% of energy cost increases above base rates and being subject to a cap on total costs, the PSA does not insulate APS from the need to finance accrued power production and supply costs.

Q. HAVE THE LIMITATIONS ASSOCIATED WITH THE PSA AND ITS IMPLEMENTATION BEEN RECOGNIZED BY THE INVESTMENT COMMUNITY?

A. Yes. In spite of the PSA, the impact of uncollected power costs on APS' cash flow metrics and ongoing uncertainty over the Company's ability to recover these expenses have sparked concern in the investment community. As noted earlier, sustained increases in power cost deferrals and a lack of clarity over the timing of rate relief led S&P to downgrade APS to "BBB-", the lowest rung on the ladder of the investment grade ratings scale. S&P noted that "by design, aspects of the PSA make it a weak tool for fuel and power cost recovery,"[23] observing that:

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[22] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005).

[23] Standard & Poor's Corporation, "Pinnacle West Capital Corp.," *RatingsDirect* (Dec. 16, 2005).

> [T]he PSA has several limitations. It allows APS to collect 90% of the difference between actual fuel, purchased power, and associated hedging costs and those reflected in retail rates. But as per the settlement, APS may not be granted an adjustment before 2006. ... In addition to a certain wait of four months for PSA adjustments to be authorized, upward adjustments are capped at 4 mils per kilowatt-hour for the life of the mechanism. As a result, all or nearly all of the PSA capacity is likely to be absorbed in APS' first PSA filing, and the utility is expected to end the summer of 2006 needing another surcharge to address additional balances that will accumulate.[24]

Indeed, S&P concluded that "the longer term risks that the terms of the PSA present" foreclosed any improvements in APS' credit standing in the short-term.[25]

Q. DOES THE PSA PROTECT APS FROM THE POTENTIAL FOR REGULATORY DISALLOWANCES?

A. No. Even with an energy cost adjustment mechanism, investors recognize the ongoing potential for regulatory disallowances. As S&P observed:

> [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]

Similarly, Fitch noted that "because of the lag between when the excess costs are incurred and when they are recovered and the potential substantial disallowances of such costs," significant uncertainties remain even for utilities with fuel and purchased power cost adjustment mechanisms.[27]

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[24] Standard & Poor's Corporation, "Research Update: Pinnacle West Capital's, Arizona Public Service's Ratings Lowered To 'BBB-'," *RatingsDirect* (Dec. 21, 2005).

[25] Standard & Poor's Corporation, "Summary: Arizona Public Service Co.," *RatingsDirect* (May 24, 2005).

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

[27] FitchRatings, "Outlook 2005: U.S. Power & Gas," *Global Power/North America Special Report* (Jan. 6, 2005) at 26.

Q. WHAT OTHER DEVELOPMENTS HAVE CONTRIBUTED TO INVESTORS' REASSESSMENT OF THE RISKS ASSOCIATED WITH THE ELECTRIC UTILITY INDUSTRY?

A. Policy evolution in the electric transmission area has been wide-reaching and investors have increasingly focused on uncertainty over operating rules and market development. Virtually all industry stakeholders have recognized that regulatory uncertainties increase the risks associated with the utility industry. For example, the Department of Energy ("DOE") identified "reducing regulatory uncertainty" as critical in stimulating increased investment in the power industry and noted that lack of clarity in the regulatory structure was inhibiting planning and investment.[28] The DOE also recognized the impact that this regulatory uncertainty has on investors' required rates of return for electric utilities:

> Because transmission assets are long lived, regulatory uncertainty increases the risks to investors and, therefore, increases the returns they need to justify transmission system investments.[29]

The 2003 blackout only served to reinforce the importance of regulatory risks for investors. The Wall Street Journal cited the debilitating impact of an "unsteady regulatory situation" and the "chaotic combination of regulated and deregulated markets" in explaining inhibitions to increased investment in the electric utility system.[30] Similarly, S&P warned investors that the partial reforms presently characterizing wholesale power markets invite prolonged dysfunction and that elevated risks will discourage new capital, "or at least make it more expensive."[31]

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[28] U.S. Department of Energy, *National Transmission Grid Study* (May 2002), at 24 and 31.

[29] *Id.* at 31.

[30] Smith, Rebecca, "Overloaded Circuits: Blackout Signals Major Weakness in U.S. Power Grid," The Wall Street Journal (Aug. 18, 2003).

[31] Standard & Poor's Corporation, "Electric Utility Blackouts Put Spotlight on Political and Regulatory Credit Risk," *RatingsDirect* (Aug. 21, 2003).

Investors recognize the potential for ongoing market volatility and remain sensitive to the strain such events can imply for regulated utilities. Investors are mindful that, even when regulation is supportive and market conditions appear relatively stable, unexpected events can trigger rapid financial deterioration before regulatory authorities are able to react.

Q. ARE INVESTORS LIKELY TO CONSIDER THE IMPACT OF THESE MARKET CONDITIONS IN ASSESSING THEIR REQUIRED RATE OF RETURN FOR APS?

A. Absolutely. While the future course of restructuring in Arizona is unclear, APS continues to face the impact of fundamental industry reforms, as Fitch recently noted:

> With the March 2005 ACC order in APS' GRC, the state has migrated to a hybrid model that relies on an integrated utility structure while providing the potential for development of a robust wholesale power market to supply customer needs over time.[32]

Fitch concluded that the development of the wholesale power market, the structure of power supply in Arizona, and the utility's role in power procurement are expected "to evolve slowly and remain subject to significant uncertainty."[33] Similarly, Moody's cited uncertainty regarding the future of competition in Arizona as a key credit challenge facing APS.[34] In addition, APS continues to confront uncertain market trends and the prospect of FERC-driven changes in the electric transmission function of the Company's business, including the uncertainties associated with the establishment of RTOs.

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[32] Fitch Ratings, "Arizona Public Service Company," *Global Power/North America Credit Analysis* (May 4, 2005).
[33] *Id.*
[34] Moody's Investors Service, "Arizona Public Service Company," *Global Credit Research Credit Opinion* (Apr. 28, 2005).

Because of potential exposure to wholesale markets, the risks of transmission uncertainties and volatile energy markets are intensified for utilities that depend on purchased power, especially for those located in the West. Reliance on purchased power to meet resource needs or fill potential shortfalls in generation magnifies the importance of maintaining the financial flexibility necessary to fund an adequate and reliable utility system. At the same time, it also exposes utilities and their investors to the ongoing regulatory uncertainties and other risks imposed by restructuring of wholesale power markets. In the minds of investors, this dependence on wholesale markets entails significant risk, which exposes the Company to the risk of reduced cash flows and unrecovered power supply costs. These challenges posed by an increasingly complex marketplace heighten the uncertainties associated with APS' utility operations while requiring the commitment of significant new capital investment to maintain and enhance service capabilities.

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

A. No. Apart from these factors, APS continues to face the normal risks inherent in operating electric utility systems, including the potential adverse effects of inflation, interest rate changes, growth, the general economy, and regulatory uncertainty and lag. As Fitch noted in a recent review of the utility industry:

> Taking a longer view, over the coming five years through 2009, the sector will increasingly face some potentially negative factors. These include rising interest rates, higher capital expenditures and volatile commodity prices.[35]

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[35] Fitch Ratings, Ltd., "Outlook 2005: U.S. Power & Gas," *Global Power North American Special Report* (Jan. 6, 2005) at 2.

Electric utilities are also confronting increased pension costs and environmental pressures that leave them exposed to uncertainties regarding emissions and potential contamination. S&P recognized the potential financial challenges posed by such factors:

> Pension obligations, environmental liabilities, and serious legal problems restrict flexibility, apart from the obligations' direct financial implications.[36]

Nuclear risk persists for those utilities involved in nuclear plants, although the exposure has shifted from construction to operating and decommissioning uncertainties. Electric utilities also remain exposed to economic vagaries within their service territories that cause service revenues and costs to fluctuate. 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.

C. Economy and Capital Markets

Q. WHAT HAS BEEN THE PATTERN OF INTEREST RATES OVER THE LAST DECADE?

A. Average long-term public utility bond rates, the monthly average prime rate, and inflation as measured by the consumer price index since 1990 are plotted in the graph below. After rising to approximately 10% in mid-1990, the average yield on long-term public utility bonds generally fell as economic conditions weakened in

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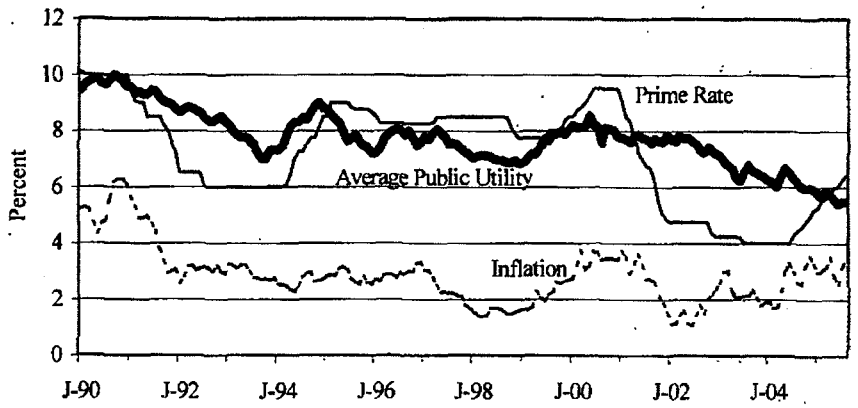
[36] Standard & Poor's Corporation, *Corporate Ratings Criteria* at 32, available at www.standardandpoors.com/ratings.

the aftermath of the 1991 Gulf war, with rates dipping below 7% in late 1993. Yields subsequently rose again in 1994, before beginning a general decline, with investors requiring approximately 5.5% from average public utility bonds in August 2005:



Q. ARE INVESTORS LIKELY TO ANTICIPATE ANY SUBSTANTIAL DECLINE IN INTEREST RATES GOING FORWARD?

A. No. Since early 2001, a great deal of attention has been focused on the actions of the Federal Reserve Board ("Fed") as it has moved successively to lower short-term interest rates in response to weakness in the United States economy. But while interest rates are currently at relatively low levels, investors are unlikely to expect any further significant declines going forward. Indeed, on December 13, 2005 the Fed raised interest rates for the thirteenth time since June 2004. The latest quarter-point increase raised the discount rate to 4.25%, or over four times the 46-year low of 1.00% in effect when the Fed began its credit-tightening campaign in 2004. As Value Line noted,[37] the general expectation is that interest rates will continue to rise with strengthening economic growth. The Wall Street Journal

[37] The Value Line Investment Survey, *Selection & Opinion* (Jun. 24, 2005) at 1659.

reported that, with growing inflationary concerns, investors are concerned that the Fed will adopt a more aggressive stance:

> [S]igns have emerged that inflation may be working itself into the economy. That would be bad news for stocks, notably because it likely would prompt the Federal Reserve to try to cool the economy by pushing interest rates higher, raising borrowing costs for businesses and consumers alike. ... Particularly worrisome to investors was the sight this week of the presidents of three regional Federal Reserve banks publicly warning the Fed is concerned about inflation. The Fed can't "let the inflation virus infect the blood supply and poison the system," said Dallas Fed President Richard Fisher yesterday. Investors took that to mean the Fed, which already has boosted short-term interest rates 11 times in the past 15 months, could continue to do so for some time.[38]

Consistent with the general expectations that these actions will also translate into higher long-term bond yields, the most recent forecast of GlobalInsight, a widely referenced forecasting service, calls for double-A public utility bond yields to reach 6.41% in 2006, averaging 6.99% over the next five years.[39] Meanwhile, the Energy Information Administration ("EIA"), a statistical agency of the DOE, anticipates that the double-A public utility bond yield will average 7.16% over the 2006-2010 period.[40] The September 1, 2005 edition of Blue Chip Financial Forecasts ("Blue Chip") also anticipates that bond yields will rise significantly over the coming year.[41]

Q. HOW HAS THE MARKET FOR COMMON EQUITY CAPITAL PERFORMED?

A. Between 1990 and early 2000 stock prices pushed steadily higher as the longest bull market in United States history continued unabated. While the S&P 500 had

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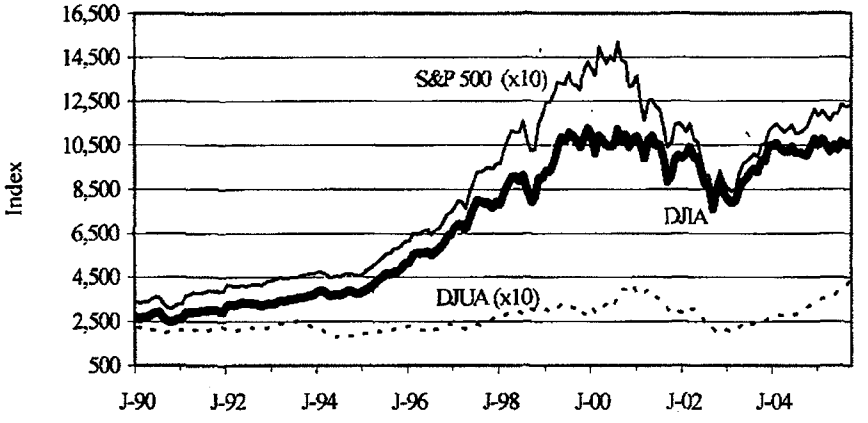
[38] Browning, E.S., "Inflation Worries Send Shivers Through Markets – Investors See Warning Signs Despite Falling Oil Prices; Watching Earnings Season," The Wall Street Journal (Oct. 7, 2005) at A1.

[39] GlobalInsight, "The U.S. Economy: The 25-Year Focus", Table 33 (First Quarter 2005).

[40] Energy Information Administration, "Annual Energy Outlook 2005", Table 19.

[41] *Blue Chip Financial Forecasts (Sep. 1, 2005) at 2.*

increased over four times in value by August 2000, mounting concerns regarding prospects for future growth, particularly for firms in the high technology sector, pushed equity prices lower, in some cases precipitously. While common stock prices have recovered strongly from their lows, the market remains volatile, with share values routinely changing in full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 1990 (the latter two indices were scaled for comparability):



Q. WHAT IS THE OUTLOOK FOR THE UNITED STATES ECONOMY?

A. While the economic picture has brightened significantly since the downturn that began in 2001, growth in gross domestic product slowed to 3.2% in the second quarter of 2005. Uncertainties over the durability and pace of economic growth continue to be impacted by overhanging government and trade deficits and higher energy prices, which have been exacerbated by the fallout from the natural disasters experienced in the Gulf Coast region. Continued conflict and instability in Iraq and the ongoing threat of terrorism also undermine consumer confidence and contribute to global economic uncertainty. These

factors cause the outlook to remain tenuous, with persistent stock and bond price volatility providing tangible evidence of the uncertainties faced by the United States economy.

Q. HOW DO THESE ECONOMIC UNCERTAINTIES AFFECT ELECTRIC UTILITIES?

A. Uncertainties over the extent and durability of the economic recovery have combined to heighten the risks faced by utilities. Stagnant economic growth would undoubtedly mean flat sales, while the potential for higher inflation and interest rates would place additional pressure on the adequacy of existing service rates. Meanwhile, the aftermath of hurricanes Katrina and Rita, coupled with continued conflict and instability in the Middle East, intensifies concerns over prolonged volatility in oil and gas prices. While the economy may ultimately return to a path of steady growth and the volatility in the capital and energy markets may abate, the underlying weaknesses now present cause considerable uncertainties to persist, which increase the risks faced by the utility industry.

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In this section, capital market estimates of the cost of equity are developed for a benchmark group of electric utilities. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and risk premium analyses conducted to estimate the cost of equity for the reference group of electric utilities.

A. Economic Standards

Q. WHAT ROLE DOES THE RATE OF 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. They 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. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

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

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Nonetheless, common equity investors still require a return on their investment, with the cost of equity being the minimum "rent" that must be paid for the use of their money. This cost of equity typically serves as the starting point for determining a fair rate of return on common equity.

The cost of equity concept is predicated on the notion that investors are risk averse, and will willingly bear additional risk only if they expect compensation for doing so. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities) investors can be induced to hold more risky assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investors' funds, more risky

assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them.

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

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and

RP_i = Risk premium required to hold risky asset i.

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

Q. DOES THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATE IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff is readily observable in certain segments of the capital markets where required rates of return can be directly inferred from market data and 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 federal 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. However, documenting the risk-return tradeoff for assets

other than fixed income securities 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. Nevertheless, it is a fundamental tenet 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. This has been supported and demonstrated by considerable empirical research in the field of finance and is confirmed by reference to historical earned rates of return, with realized rates of return on common stocks exceeding those on government and corporate bonds over the long-term.

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. Debt, preferred stock, and common equity vary considerably in risk because they have different characteristics and priorities.

When investors loan money in the form of debt (*e.g.*, long-term bonds), they enter into a contract whereby the utility agrees to pay the bondholders a specified amount of interest and to repay the principal of the loan in full. The bondholders have a senior claim on available cash flow for these payments, and if the utility fails to make them, they may force it into bankruptcy and liquidation for settlement of unpaid claims. Similarly, when a utility sells investors preferred stock, the utility promises to pay preferred stockholders specified dividends and, typically, to retire the preferred stock on a predetermined schedule. While the rights of preferred stockholders to available cash flow for these payments are junior to

creditors, and preferred stockholders cannot compel bankruptcy, their claims are senior to those of common shareholders.

The last investors in line are common shareholders. They receive only the cash flow, if any, that remains after all other claimants – employees, suppliers, governments, lenders, and preferred stockholders – 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, is considerably higher than the yield on the utility's long-term debt or preferred stock, which have more certain, senior claims.

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

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, and 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 upon to determine a utility's cost of equity because no single approach can be regarded as wholly reliable. As the Federal Communications Commission 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.[42]

Therefore, I used both the DCF model and risk premium methods to estimate the cost of equity. In addition, I also evaluated a fair rate of return using a comparable earnings approach based on investors' current expectations in the capital markets. 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.

B. Discounted Cash Flow Analyses

Q. HOW ARE DCF MODELS USED TO ESTIMATE THE COST OF EQUITY?

A. The use of DCF models is essentially an 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 expected rates of return, 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,

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

or cost of equity, that investors presumptively used in bidding the stock to that price.

Q. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A. DCF models are derived from a theory of valuation which assumes 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, or the cost of equity. 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. HAS THIS GENERAL FORM OF THE DCF MODEL CUSTOMARILY BEEN USED TO ESTIMATE THE COST OF EQUITY IN RATE CASES?

A. No. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant growth" form. But converting the general form of the DCF model to the constant growth DCF model requires a number of strict assumptions. These include:

- A constant growth rate for both dividends and earnings;
- A stable dividend payout ratio;

- A discount rate exceeding 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.

Given these assumptions, the general form of the DCF model can be reduced to the more manageable formula of:

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

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

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

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

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. ARE THE ASSUMPTIONS UNDERLYING THE CONSTANT GROWTH FORM OF THE DCF MODEL MET IN THE REAL WORLD?

A. In practice, none of the assumptions required to convert the general form of the DCF model to the constant growth form are ever strictly met. Nevertheless, where earnings are derived from stable activities, and earnings, dividends, and book value

track fairly closely, the constant growth form of the DCF model offers a reasonable working approximation of stock valuation that provides useful insight as to investors' required rate of return.

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

A. In estimating the cost of equity, the DCF model is typically applied to publicly traded firms engaged in similar business activities. In order to reflect the risks and prospects associated with APS' jurisdictional utility operations, my DCF analyses focused on a reference group of other electric utilities composed of those companies included by Value Line in their Electric Utilities (West) Industry group. Excluded from my analyses were five firms that either do not pay common dividends or were rated below investment grade by S&P.

The consolidated corporate credit ratings published by S&P for the individual firms in the electric utility proxy group ranged from "BBB-" to "A-", with the average being "BBB". As noted earlier, following S&P's December 2005 downgrade, APS is currently assigned a rating of "BBB-", which corresponds to the very bottom end of the proxy group range and represents the lowest investment grade rating. Given that these ten utilities are all engaged in utility operations in the Western region of the U.S., investors are likely to regard this group as facing similar market conditions and having comparable risks and prospects. The Supreme Court recognized the relevance of geographical location in *Bluefield,* noting that utilities are entitled to earn a return equal to those being made by firms of comparable risk "in the same general part of the country."[43] Indeed, there are important factors

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[43] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679, 692 (1923).

distinguishing Western utilities from those located in other regions, such as the ongoing uncertainties associated with Western energy markets, that are important considerations in evaluating investors' required rate of return for APS.

Q. WHY DID YOU EXCLUDE FIRMS THAT DO NOT PAY COMMON DIVIDENDS OR HAVE BELOW INVESTMENT GRADE BOND RATINGS FROM YOUR BENCHMARK GROUP?

A. As discussed earlier, under the DCF approach, observable stock prices are a function of the cash flows that investors expect to receive, discounted at their required rate of return. Because dividend payments are a key parameter required to apply the DCF method, this hinders application of the DCF model to firms that do not pay common dividends. Meanwhile, the financial stress and lack of stability that accompanies below investment grade bond ratings violates the comparable-risk standard and greatly complicates any determination of investors' long-term expectations that form the basis for DCF applications.

Q. WHAT OTHER CONSIDERATIONS SUPPORT THE USE OF A PROXY GROUP IN ESTIMATING THE COST OF EQUITY FOR APS?

A. Apart from recognizing the inherent risks and prospects for comparable risk utilities, reference to a proxy group of utilities is essential to insulate against vagaries that can result when the stochastic process involved in estimating the cost of equity is applied to a single company. The cost of equity is inherently unobservable and can only be inferred indirectly by reference to available capital market data. To the extent that the data used to apply the DCF model does not capture the expectations that investors have incorporated into current stock prices, the resulting cost of equity estimates will be biased and fail to reflect investors' required rate of return.

As the FERC noted in its July 3, 2003 *Order on Initial Decision* in Docket No. RP00-107-000, even using a limited group of companies does not remove the potential for error:

> Both Staff and Williston agreed that a proxy group of only three companies presented problems because "a single company will have a magnified influence on the group results." It was with those changing market dynamics in mind that witnesses of both Staff and Williston proposed to expand the group of proxy companies to determine a zone of reasonableness.

The 10-company proxy group composed of utilities operating in the Western U.S. is consistent not only with shared investment risks, but also with the need to ensure against the potential that a single cost of equity estimate may not reflect investors' required rate of return.

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. Since book value, dividends, earnings, and price are all assumed to move in lock-step in the constant growth DCF model, estimates of expected growth are sometimes derived from historical rates of growth in these variables under the presumption that investors expect these rates of growth to continue into the future. Alternatively, a firm's internal growth can be estimated based on the product of its earnings retention ratio and earned rate of return on equity. This growth estimate may rely on either historical or projected data, or both. A third approach is to rely on security analysts' projections of growth as proxies for investors' expectations. 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 PROXY GROUP OF ELECTRIC UTILITIES DETERMINED?

A. Estimates of dividends to be paid by each of these electric 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 electric utility proxy group are presented on Attachment WEA-1. As shown there, dividend yields for the ten firms in the electric utility proxy group ranged from 2.2% to 4.6%, with the average being 3.5%.

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

A. 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. Thus, the only "*g*" that matters in applying the DCF model is that which investors expect and have embodied in current market prices.

Q. ARE HISTORICAL DIVIDEND GROWTH RATES LIKELY TO PROVIDE A MEANINGFUL GUIDE TO INVESTORS' GROWTH EXPECTATIONS FOR ELECTRIC UTILITIES?

A. No. In response to more accentuated business risks in the industry, electric utilities adopted dividend policies that were much more conservative than in the past. As a result, dividend growth in the electric utility industry has remained largely stagnant

in recent years as utilities conserved financial resources to provide a hedge against heightened uncertainties. Responding to this trend, investors' focus increasingly shifted from dividends to earnings as a measure of long-term growth, as payout ratios for firms in the electric utility industry trended downward from approximately 80% historically to on the order of 60%.[44]

Q. WHAT ARE INVESTORS LIKELY EXPECTING IN THE WAY OF GROWTH FOR THE ELECTRIC UTILITY PROXY GROUP?

A. As the industry recovers from the financial challenges of the last several years, some electric utilities have begun to reevaluate their dividend policies and reinstate increases to their quarterly payout. While investors have recently expressed renewed interest in dividend payments, Value Line's most recent forecast indicates negative projected dividend growth for one of the proxy firms, while one is listed as "Nil" and another as "NMF".[45] Negative or zero growth rates imply a cost of equity equal to, or below, the utility's dividend yield. Such nonsensical results provide little guidance as to investors' expectations for the electric utility proxy group.

Q. WHAT OTHER TRENDS DO INVESTORS CONSIDER IN DEVELOPING GROWTH EXPECTATIONS?

A. Trends in earnings, which ultimately support future dividends and share prices, are likely to play a pivotal role in determining investors' long-term growth expectations. Indeed, the importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As

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[44] See, *e.g.*, The Value Line Investment Survey (Sep. 15, 1995 at 161, Aug. 12, 2005 at 1776).

[45] The Value Line Investment Survey (Aug. 12, 2005).

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.[46]

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%.[47]

The fact that investment advisory services, such as Value Line and I/B/E/S International, Inc. ("IBES"), 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.[48] 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:

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[46] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).

[47] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

[48] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

Earnings and cash flow are considered far more important than book value and dividends.[49]

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF EARNINGS GROWTH FOR THE FIRMS IN THE ELECTRIC UTILITY PROXY GROUP?

A. The earnings growth projections for each of the firms in the electric utility proxy group reported by IBES and published in S&P's *Earnings Guide* are displayed on Attachment WEA-2. Also presented are the earnings per share ("EPS") growth projections reported by Value Line, First Call Corporation ("First Call"), Zacks Investment Research ("Zacks"), and Reuters, Inc. ("Reuters"). As shown there, these security analysts' projections suggested growth on the order of 5.4% to 5.7% for the reference group of electric utilities:

Electric Utility Proxy Group

Service	Growth Rate
IBES	5.4%
Value Line	5.5%
First Call	5.5%
Zacks	5.7%
Reuters	5.7%

Q. WHAT CONSIDERATIONS ARE RELEVANT IN EVALUATING THESE NEAR-TERM GROWTH RATES FOR ELECTRIC UTILITIES?

A. Short-term projected growth rates may be colored by lingering uncertainties regarding the near-term direction of the economy in general and the spate of

[49] *Id.* at 88.

challenges recently faced in the electric power industry specifically. This short-term "hangover" is exemplified by Value Line, which has assigned its Utilities sector the lowest ranking of all 10 sectors it covers for year-ahead stock price performance,[50] while noting that "[t]he electric utility industry carries a below-average industry Timeliness rank."[51] While this cautious outlook may be indicative of relatively low near-term growth projections, it does not necessarily reflect investors' long-term expectations for the industry.

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED FOR USE IN 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 relationships 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.

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

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[50] The Value Line Investment Survey, *Selection & Opinion* (Jul. 29, 2005) at 1606.

[51] The Value Line Investment Survey (July 1, 2005) at 695.

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 PROXY GROUP OF ELECTRIC UTILITIES?

A. The sustainable, "br+sv" growth rates for each firm in the proxy group are shown on Attachment WEA-3. For each firm, the expected retention ratio (b) was 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 average 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. As shown there, incorporating this method resulted in an average expected growth rate for the group of electric utilities of 4.6%.

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO THE GROWTH EXPECTATIONS IMPLIED FOR THE PROXY GROUP OF WESTERN UTILITIES?

A. I concluded that the measures discussed above indicated growth on the order of 5.5% for the average firm in the utility proxy group.

Q. WHAT COST OF EQUITY WAS IMPLIED FOR THE PROXY GROUP OF UTILITIES USING THE DCF MODEL?

A. Combining the 3.5% average dividend yield with a growth rate of 5.5% implied a DCF cost of equity of 9.0%.

Q. DO YOU BELIEVE THIS CONSTANT GROWTH DCF ESTIMATE REPRESENTS A REASONABLE COST OF EQUITY FOR APS OR THE PROXY GROUP OF ELECTRIC UTILITIES?

A. No. As I noted earlier, 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, and regulators have customarily considered the results of alternative approaches in determining allowed returns. The need to consider alternative methods is especially important where the results of one approach deviate significantly from cost of equity estimates produced by other applications. Indeed, as discussed subsequently, the results of alternative risk premium methods and the comparable earnings approach suggest a cost of equity far in excess of this single DCF value.

Moreover, as noted earlier, the short-term projected growth rates typically used to apply the DCF model may be colored by lingering economic and industry uncertainties, as exemplified by Value Line's relatively pessimistic rankings for the utility sector. As a result of this cautious near-term outlook, DCF growth rates do not necessarily capture investors' long-term expectations for the industry, and the resulting cost of equity estimates will be downward-biased. Accordingly, it would be unreasonable to establish an ROE based on this single DCF approach.

C. Risk Premium Analyses

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. As I mentioned previously, because the cost of equity is inherently unobservable, no single method should be considered a reliable guide to investors' required rate of return. Accordingly, I also evaluated the cost of equity for APS using the risk premium method. My applications of the risk premium method provide alternative approaches to measure equity risk premiums that focus specifically on data for electric utilities and employ alternative estimates of investors' required rates of return.

Q. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A. The risk premium method of estimating investors' required rate of return extends the risk-return tradeoff observed with bonds to common stocks. The cost of equity is estimated by first determining the additional return investors require to forego the relative safety of bonds and to bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, the risk premium method directly estimates investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A. I based my estimates of equity risk premiums for electric utilities on (1) surveys of previously authorized rates of return on common equity, (2) realized rates of return, and (3) alternative applications of the Capital Asset Pricing Model ("CAPM").

Authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such returns should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, this data provides a logical and frequently referenced basis for estimating equity risk premiums.

Under the realized-rate-of-return approach, equity risk premiums are calculated by measuring the rate of return (including dividends, interest, and capital gains and losses) actually realized on an investment in common stocks and bonds over historical periods. The realized rate of return on bonds is then subtracted from the return earned on common stocks to measure equity risk premiums.

The CAPM approach measures the market-expected return for a security as the sum of a risk-free rate and a risk premium based on the portion of a security's risk that cannot be eliminated by holding a well-diversified portfolio. Under the CAPM, risk is represented by the beta coefficient (β), which measures the volatility of a security's price relative to the market as a whole. While controversy surrounds the use of beta to measure an individual utility's investment risk, the CAPM is routinely referenced in the financial literature and in regulatory proceedings.

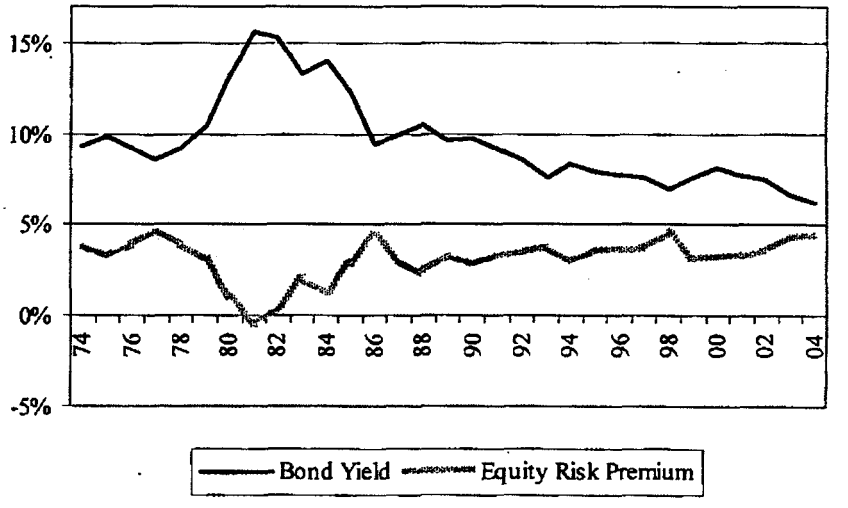
While these methods are premised on different assumptions, each having their own strengths and weaknesses, they are widely accepted approaches that have been routinely referenced in estimating the cost of equity for regulated utilities.

Q. HOW DID YOU IMPLEMENT THE RISK PREMIUM APPROACH USING SURVEYS OF ALLOWED RATES OF RETURN?

A. Surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. The rates of return on common equity authorized utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates ("RRA") and published in its Regulatory Focus report. In Attachment WEA-4, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2004. Over this 31-year period, these equity risk premiums for electric utilities averaged 3.17%, and the yield on public utility bonds averaged 9.59%.

Q. IS THERE ANY RISK PREMIUM BEHAVIOR THAT NEEDS TO BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. To illustrate, the graph below plots the yields on public utility bonds (solid line) and equity risk premiums (shaded line) shown on Attachment WEA-4:



The graph clearly illustrates that the higher the level of interest rates, the lower the equity risk premium, and vice versa. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated. Finally, it is important to recognize that the historical focus of the risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing electric utility service. As a result, they are likely to understate the cost of equity for a firm operating in today's electric power industry.

Q. WHAT COST OF EQUITY IS IMPLIED BY SURVEYS OF ALLOWED RATES OF RETURN ON EQUITY?

A. As illustrated above, the inverse relationship between interest rates and equity risk premiums is evident. Based on the regression output between the interest rates and

equity risk premiums displayed at the bottom of page 1 of Attachment WEA-4, the equity risk premium for electric utilities increased approximately 43 basis points for each percentage point drop in the yield on average public utility bonds.[52] As illustrated there, with the average yield on public utility bonds in August 2005 being 5.51%, this implied a current equity risk premium of 4.93% for electric utilities. Adding this equity risk premium to the August 2005 average yield on triple-B public utility bonds of 5.80% produces a current cost of equity for the utilities in the benchmark group of approximately 10.7%.

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING RISK PREMIUM METHODS?

A. As discussed earlier, there is widespread consensus that interest rates will increase as the economy continues to strengthen, with the Fed's recent actions indicative of tighter credit conditions and higher interest rates in the years ahead. As a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use of current bond yields, I also applied the alternative risk premium methods using forecasted bond yields for 2006, based on an average of the projections published by GlobalInsight, EIA, and Blue Chip.[53]

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[52] The average public utility bond yield reflects the average of the yields for bonds rated "Aa", "A", and "Baa" by Moody's.

[53] An analogous approach using forecasted interest rates was adopted by the staff of the Florida Public Service Commission ("FPSC") in a May 20, 2004 *Memorandum* in Docket No. 040006-WS and in the testimony of FPSC staff witness Andrew L. Maurey in Docket No. 000824-EI (Jan. 2002).

Q. WHAT COST OF EQUITY WAS PRODUCED BY THE AUTHORIZED RATE OF RETURN APPROACH AFTER INCORPORATING THE AVERAGE BOND YIELD FORECAST?

A. As shown on page 2 of Attachment WEA-4, incorporating a forecasted yield for 2006 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.37% for electric utilities. Adding this equity risk premium to the implied yield on triple-B public utility bonds for 2006 of 7.0% resulted in an implied cost of equity of approximately 11.4%.

Q. HOW DID YOU APPLY THE REALIZED-RATE-OF-RETURN APPROACH?

A. Widely used in academia, the realized-rate-of-return approach is based on the assumption that, given a sufficiently large number of observations over long historical periods, average realized market rates of return will converge to investors' required rates of return. From a more practical perspective, investors may base their expectations for the future on, or may have come to expect that they will earn, rates of return corresponding to those realized in the past. Indeed, average realized rates of return for historical periods are widely reported to investors in the financial press and by investment advisory services as a guide to future performance. By focusing on data for utilities specifically, my realized rate of return approach avoided the need to make assumptions regarding relative risk (*e.g.*, beta) that are often embodied in applications of this method.

Stock price and dividend data for the electric utilities included in the S&P 500 Composite Index ("S&P 500") are available for the period 1946 through 2004. As shown in Attachment WEA-5, over this 58-year period realized rates of return for these utilities have exceeded those on average public utility bonds by an average of 4.04%. In contrast to other risk premium approaches, the realized-rate-of-return

method assumes that equity risk premiums are stationary over time; therefore, no adjustment for the inverse relationship between equity risk premiums and interest rates was made. Adding this 4.04% equity risk premium to the August 2005 yield of 5.80% on triple-B public utility bonds produces a current cost of equity for the electric utility proxy group of approximately 9.8%.

Once again, however, this does not consider the anticipated increase in bond yields through 2006. Adding this 4.04% equity risk premium to the 7.0% forecasted yield on triple-B public utility bonds for 2006 implies a cost of equity of approximately 11.0%.

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Under the CAPM, investors are assumed to be fully diversified, so the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole. Beta reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond relatively less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

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.

I applied the CAPM to the seventeen companies in the electric utility proxy group using market risk premiums (R_m - R_f) based on (1) forward-looking estimates of investors' required rates of return and (2) historical realized rates of return.

Q. PLEASE DESCRIBE YOUR FORWARD-LOOKING APPLICATION OF THE CAPM.

A. Application of the CAPM to the utilities in the proxy group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Attachment WEA-6. Rather than using historical data, the expected market rate of return was estimated by conducting a DCF analysis on the 356 dividend paying firms in the S&P 500, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value.[54]

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. Based on the weighted average of the projections for the 356 individual firms, current estimates imply an average growth rate over the next five years of 11.4%. Combining this average growth rate with a dividend yield of 2.1% results in a current cost of equity estimate for the market as a whole of approximately 13.5%. Subtracting a 4.5% risk-free rate based on the September 2005 average yield on 20-year Treasury bonds from the 13.5% forward-looking rate of return produced a market equity risk premium of 9.0%. Multiplying this risk premium by the average Value Line beta of 0.89 for the utilities in the proxy group, and then adding the resulting 8.0% risk premium to the

[54] This is analogous to the approach relied on by the Illinois Commerce Commission Staff in Docket No. 96-0486 (*Testimony of Joy Nicdao-Cuyygan*).

September 2005 average long-term Treasury bond yield, resulted in a current cost of equity of approximately 12.5%.

Q. WHAT COST OF EQUITY IS IMPLIED BY THIS FORWARD-LOOKING APPLICATION OF THE CAPM AFTER INCORPORATING PROJECTED GOVERNMENT BOND YIELDS FOR 2006?

A. As shown on page 2 of Attachment WEA-6, interest rate projections published by GlobalInsight, EIA, and Blue Chip imply a projected yield on 20-year Treasury bonds of 5.5% for 2006, which results in a market risk premium of 8.0%. Once again multiplying the market risk premium by the average Value Line beta of 0.89 for the electric utilities in the proxy group, and then adding the resulting 7.1% risk premium to the 5.5% long-term Treasury bond yield for 2006, implied a cost of equity of approximately 12.6%.

Q. WHAT OTHER CAPM ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. I also applied the CAPM using risk premiums based on historical realized rates of return. This approach to estimating investors' equity risk premiums is premised on the assumption that, given a sufficiently large number of observations over long, historical periods, average realized market rates of return will converge to investors' required rates of return.

Q. WHAT CAPM COST OF EQUITY IS PRODUCED BASED ON HISTORICAL REALIZED RATES OF RETURN FOR STOCKS AND LONG-TERM GOVERNMENT BONDS?

A. I applied the CAPM using data published by Ibbotson Associates, which is perhaps the most exhaustive and widely referenced annual study of realized rates of return. Application of the CAPM based on historical realized rates of return is presented in Attachment WEA-7. In their *2005 Yearbook, Valuation Edition*, Ibbotson Associates reported that, over the period from 1926 through 2004, the arithmetic

mean realized rate of return on the S&P 500 exceeded that on long-term government bonds by 7.2%.[55] Multiplying this historical market risk premium by the average Value Line beta of 0.89 produced an equity risk premium of 6.4% for the electric utility proxy group. As shown on page 1 of Attachment WEA-7, adding this equity risk premium to the September 2005 average yield on 20-year Treasury bonds of 4.5% resulted in an implied cost of equity of 10.9%. As shown on page 2 of Attachment WEA-7, after incorporating a the 5.5% projected government bond yield for 2006, application of the CAPM based on historical realized rates of return implied a cost of equity of 11.9%.

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM USING HISTORICAL REALIZED RATES OF RETURN?

A. The CAPM model, like the DCF approach, is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to accurately estimate required returns the CAPM must be applied using data that reflects the expectations of actual investors. While reference to historical data represents one way to apply the CAPM, these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. As a result, applications of the CAPM that look directly at investors' expectations in the capital markets are apt to provide a more meaningful guide to investors' required rate of return. Accordingly, because the historical approach does not incorporate forward-looking estimates, it was given less weight in arriving at my recommended return on equity.

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[55] Ibbotson Associates computes the equity risk premium by subtracting the income return (not the total return) on long-term Treasury bonds from the return on common stocks. As Ibbotson Associates noted [*2005 Yearbook, Valuation Edition* at 75]:

> Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR RISK PREMIUM ANALYSES.

A. The cost of equity estimates implied by my risk premium analyses are summarized in the following table:

Risk Premium Approach	Cost of Equity Estimate
Authorized Returns	
Current Yield	10.7%
Projected Yield	11.4%
Realized Rates of Return	
Current Yield	9.8%
Projected Yield	11.0%
CAPM - Forward-looking	
Current Yield	12.5%
Projected Yield	12.6%
CAPM - Historical	
Current Yield	10.9%
Projected Yield	11.9%

D. Comparable Earnings Method

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. As I noted earlier, I also evaluated the cost of equity using the comparable earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return

necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This comparable earnings approach is consistent with the economic underpinnings for a fair rate of return established by the Supreme Court. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR UTILITIES BASED ON THIS APPROACH?

A. With respect to expectations for electric utilities specifically, the most recent edition of Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5% in 2005 and 2006, increasing to 11.0% over its three-to-five year forecast horizon.[56] Meanwhile, Value Line expects that natural gas distribution utilities will earn an average rate of return on common equity of 12.0% in 2005 and 2006, and 12.5% for 2008-2010.[57]

Q. CAN THE COMPARABLE EARNINGS METHOD BE APPLIED TO OTHER FIRMS OF SIMILAR RISK?

A. Yes. Under the regulatory standards established by *Hope* and *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. Consistent with this accepted regulatory standard, I also applied the comparable earnings approach based on a reference group of companies in the unregulated sector of the economy.

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[56] The Value Line Investment Survey (Sep. 2, 2005) at 156.

[57] The Value Line Investment Survey (Sep. 16, 2005) at 459.

My assessment of comparable risk relied on two objective benchmarks for the risks associated with common stocks -- Value Line's Safety Rank and beta. The Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest), is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. As discussed earlier, Value Line's beta values provide a measure of stock price variability as compared with the firms in the New York Stock Exchange Composite Index, with a beta less than 1.0 indicating that a stock tends to fluctuate less than the market as a whole (lower risk) while a beta greater than 1.0 indicates that the stock tends to fluctuate more than the market (greater risk).

The average Value Line Safety Ranking for the firms in the proxy group is "2", with beta values for the ten electric utilities ranging from 0.70 to 1.05. Accordingly, my reference group was composed of those U.S. companies followed by Value Line that 1) pay common dividends, 2) have a Safety Rank of "2", and 3) have beta values between 0.70 and 1.05. Value Line's projections indicate that its analysts expect that rates of return on shareholders' equity for the resulting group of 151 firms will average 15.7%, with the median being 14.0%.[58]

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE RESULTS OF THE COMPARABLE EARNINGS APPROACH?

A. Based on the results discussed above, I concluded that the comparable earnings approach implies a fair rate of return on equity of at least 11.0% to 12.0%.

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[58] www.valueline.com (Retrieved Oct. 11, 2005).

E. Proxy Group Cost of Equity

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO THE COST OF EQUITY FOR THE PROXY GROUP OF UTILITIES?

A. In light of anticipated capital market trends and the recent challenges experienced in the electric utility industry, caution should be exercised in interpreting the results of DCF and risk premium applications. As noted earlier, the single constant growth DCF result is out of line with the preponderance of estimates produced by the risk premium and comparable earnings approaches and should not be viewed in isolation, especially considering the potential for downward bias when DCF growth rates do not capture investors' long-term expectations. Moreover, accelerating economic growth and expectations for higher interest rates suggest that 2006 estimates should receive more weight. Accordingly, based on the results of my quantitative analyses, and my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of equity for the electric utility proxy group is in the 10.8% to 11.8% range.

F. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock

and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[59]

Alternatively, a study of recent data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[60] Similarly, Pinnacle West incurred flotation costs equal to approximately 3.5% of net proceeds in connection with its sale of additional common shares in 2005.[61]

Applying these expense percentages to a representative dividend yield for a utility of 3.5% implies a flotation cost adjustment on the order of 12 to 35 basis points.[62]

Q. IS THE NEED FOR A FLOTATION COST ADJUSTMENT TO COMPENSATE FOR PAST EQUITY ISSUES RECOGNIZED IN THE FINANCIAL LITERATURE?

A. Yes. In a *Public Utilities Fortnightly* article, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[63] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

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[59] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utility Reports (1994) at 166.

[60] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[61] Legal and other underwriting costs totaled $8,569,675, while net proceeds from the stock issuance amounted to $247,420,325.

[62] As shown on Attachment WEA-1, Pinnacle West's dividend yield is significantly higher than the average for the group, at 4.5%. Accordingly, the implied flotation cost adjustment would be correspondingly higher, at 16 to 45 basis points.

[63] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly* (May, 2, 1985).

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[64]

Q. CAN YOU PROVIDE A SIMPLE NUMERICAL EXAMPLE ILLUSTRATING WHY A FLOTATION COST ADJUSTMENT IS NECESSARY TO ACCOUNT FOR PAST FLOTATION COSTS?

A. Yes. The following example demonstrates that investors will not have the opportunity to earn their required rate of return (*i.e.*, dividend yield plus expected growth) unless an allowance for past flotation costs is included in the allowed rate of return on equity. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 11.5%, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5%), and that growth is expected to be 6.5% annually. As developed below, if the allowed rate of return on common equity is only equal to the utility's 11.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 6.25%, instead of 6.5%:

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[64] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports (1994) at 175.

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.50%	$ 1.09	$ 0.50	45.7%
2	$ 9.52	$ 0.59	$10.11	$10.62	1.050	11.50%	$ 1.16	$ 0.53	45.7%
3	$ 9.52	$ 0.63	$10.75	$11.29	1.050	11.50%	$ 1.24	$ 0.56	45.7%
Growth			6.25%	6.25%			6.25%	6.25%	

The reason that investors never really earn 11.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Q. CAN YOU ILLUSTRATE HOW THE FLOTATION COST ADJUSTMENT ALLOWS INVESTORS TO BE FULLY COMPENSATED FOR THE IMPACT OF PAST ISSUANCE COSTS?

A. Yes. As discussed earlier, one method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown below, by allowing a rate of return on common equity of 11.75% (an 11.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 11.5% required rate of return, since actual growth is now equal to 6.5%:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.75%	$ 1.12	$ 0.50	44.7%
2	$ 9.52	$ 0.62	$10.14	$10.65	1.050	11.75%	$ 1.19	$ 0.53	44.7%
3	$ 9.52	$ 0.66	$10.80	$11.34	1.050	11.75%	$ 1.27	$ 0.57	44.7%
Growth			6.50%	6.50%			6.50%	6.50%	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on

common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q. WHAT THEN IS YOUR CONCLUSION REGARDING A FAIR RATE OF RETURN ON EQUITY FOR THE COMPANIES IN YOUR PROXY GROUP?

A. In order to account for the impact of past issuance costs, I recommend a flotation cost adjustment of 20 basis points, which roughly corresponds with the midpoint of the range discussed earlier. After incorporating an adjustment for flotation costs of 20 basis points to my "bare bones" cost of equity range, I concluded that a fair rate of return on equity for the proxy group of utilities is currently in the 11.0% to 12.0% range, with a midpoint of 11.5%.

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.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW APS AN ADEQUATE RATE OF RETURN ON EQUITY?

A. Given the social and economic importance of the electric utility industry, it is essential to maintain reliable and economical service to all consumers. While APS remains committed to provide reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal.

Q. DO CUSTOMERS ALSO BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. While providing an ROE that is sufficient to maintain APS' ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. 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 necessary capital is impaired and service quality is compromised. To continue to meet potential challenges successfully and economically, it is crucial that APS receive adequate support for its credit standing.

Q. WHAT DANGER DOES AN INADEQUATE RATE OF RETURN POSE TO APS?

A. In light of APS' present rating, an inadequate rate of return imposed in this proceeding would further pressure APS' financial flexibility and credit standing. In order to meet rising demand for electricity across its service territory, APS has sought to acquire additional power resources to ensure its ability to maintain adequate reserve margins and provide reliable service. From 1996 through 2004, APS invested about $3.6 billion to expand generation and upgrade transmission and distribution systems, and the Company's long-term plans include significant plant investment to ensure that the energy needs of its service territory are met. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on APS. The investment community has specifically noted the increasing capital

expenditures required to keep pace with APS' growing service territory as a significant credit challenge facing the Company, with Moody's concluding that:

> [S]upportive regulatory treatment remains key to the company's ability to maintain financial strength in light of significant needs for capital investment to serve a growing service territory.[65]

Q. DO THE POTENTIAL EXPOSURES FACED BY APS HIGHLIGHT THE NEED FOR ONGOING SUPPORT OF THE COMPANY'S FINANCIAL STRENGTH AND ABILITY TO ATTRACT CAPITAL?

A. Most definitely. APS faces a number of potential challenges that might require the relatively swift commitment of considerable capital resources in order to maintain the high level of service to which its customers have become accustomed. Given the potential for significant volatility in wholesale fuel and energy markets and APS' lack of control over the timing of such events, the Company must have the wherewithal to meet these challenges even when capital and energy market conditions are unfavorable. Potential capital requirements mandated by environmental regulations also imply additional financial strain.[66] For an electric 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.

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[65] Moody's Investors Service, "Rating Action: Arizona Public Service Company," *Global Credit Research* (Jan. 10, 2006).

[66] Mr. Fox discusses the necessary capital expenditures associated with environmental changes to the Cholla, Four Corners and Navajo generating plants.

Q. WHAT LESSONS CAN BE LEARNED FROM RECENT EVENTS IN THE ENERGY INDUSTRY?

A. Experience demonstrates that, while investor confidence can evaporate almost overnight, it is difficult to recover and the damage is not quickly or easily reversed. Events in the Western U.S. provide a dramatic illustration of 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.

Given the investment community's view that APS continues to be challenged by regulatory lag and pressures linked to mounting power cost deferrals, the perception of a lack of regulatory support would be of utmost concern to investors. Moody's recently noted that:

> The ratings of APS and Pinnacle are likely to be downgraded unless there are clear signals that APS will receive timely and full recovery of its increased costs such that we would expect their credit metrics to return to levels commensurate with those of similarly rated utility companies.[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. While APS' conservative posture has benefited customers and provided a strong platform for continued success, actions that serve to erode financial strength or impair financial flexibility could have swift and damaging consequences. The cost of providing APS an adequate

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[67] Moody's Investors Service, "Rating Action: Arizona Public Service Company," *Global Credit Research* (Jan. 10, 2006)

return is small relative to the potential benefits of a strong utility providing reliable service and fostering continued growth.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING A UTILITY'S ACCESS TO CAPITAL?

A. Considering investors' heightened awareness of the risks associated with the electric power industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial in preserving access to capital. Investors recognize 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.[68]

Investors recognize the importance of financial flexibility, especially considering the capital markets' ability to constrict access to capital when investors' confidence is compromised. As S&P observed:

> When examining the quality of regulation, Standard & Poor's factors in what level of support the utility might get in times of distress, when its needs are most acute.[69]

Q. ARE THESE CONCERNS GERMANE TO APS AND ITS INVESTORS?

A. Yes. Investors recognize that regulation has its own risks. With respect to APS specifically, the three major bond rating agencies have all noted the near-term

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[68] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric/Gas/Water," *RatingsDirect* (May 3, 2005) at 1.

[69] Standard & Poor's Corporation, "Regulation and Credit Quality in the U.S. Utility Sector," *RatingsDirect* (Jan. 30, 2003).

challenges posed by regulatory uncertainty, while explicitly citing the potential that adverse regulatory rulings could further compromise the Company's credit standing.[70]

As discussed earlier, of particular concern to investors is the impact of regulatory lag and cost-recovery on the APS' ability to earn its authorized ROE. S&P noted the importance of predictability and consistency, as well as the need to reduce rate-case lag, in its assessment of a utility's operating environment.[71] Foreshadowing its January 2006 downgrade, S&P concluded that the "pace and disposition" of APS' request for a PSA surcharge will be "critical to credit quality," with the rating agency expressing concern over APS' ability to recover power supply costs:

> [I]t is clear that timely near-term cost collection will be the key driver of credit quality. Standard & Poor's is becoming increasingly concerned with the utility's ability to achieve this. A relatively weak power supply adjustment mechanism, in combination with rapidly escalating and volatile gas prices, as well as the potential for a protracted surcharge proceeding, could cause deterioration in financial performance which, year to date, has been sub par for the rating.[72]

Coupled with the use of an historical test year and the potential for protracted proceedings, S&P concluded that "APS' near-term challenges are largely related to regulatory lag."[73]

Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to market and regulatory uncertainties has increased

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[70] See, *e.g.*, Standard & Poor's Corporation, "Summary: Arizona Public Service Co.," *RatingsDirect* (Jan 6, 2006); Moody's Investors Service, "Rating Action: Arizona Public Service Company," *Credit Research* (Jan. 10, 2006); Fitch Ratings Ltd., "Fitch Places PNW and APS on Rating Watch Negative" (Jan. 6, 2006).

[71] Standard & Poor's Corporation, "U.S. Utility Regulation Returns to Center Stage," *RatingsDirect* (Apr. 14, 2005).

[72] Standard & Poor's Corporation, "Summary: Arizona Public Service Company," *RatingsDirect* (Oct. 4, 2005).

[73] Standard & Poor's Corporation, "Summary: Arizona Public Service Co.," *RatingsDirect* (Jun. 24, 2005).

dramatically. Investors have many alternatives and competition for capital is intense. Lingering uncertainties from a prior era, as well as new challenges in the electric power industry, breed reluctance to make the long-term commitment of capital that is required to ensure the reliable and economic supply of electricity that customers both demand and deserve. Thus, while customers might realize short-term "savings" through a downward-biased ROE, these will prove illusory when the utility is precluded from making investments that are consistent with providing sustained, high quality service at the lowest possible price in the long run.

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.

Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN APS' REQUESTED CAPITAL STRUCTURE?

A. APS' capital structure is presented in the testimony of Mr. Brandt. As summarized in his testimony, the common equity ratio used to compute APS' overall rate of return was approximately 55% in this filing.

Q. WHAT WAS THE AVERAGE CAPITALIZATION MAINTAINED BY THE REFERENCE GROUP OF UTILITIES?

A. As shown on Attachment WEA-8, for the ten firms in the proxy group, common equity ratios at December 31, 2004 ranged from 37.2% to 65.8% and averaged 49.7%.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE UTILITY INDUSTRY HAVE FOR THE CAPITAL STRUCTURES MAINTAINED BY UTILITIES?

A. The decline in credit quality in the electric industry is indicative of the need for utilities to strengthen their balance sheets to deal with an increasingly uncertain and competitive market. S&P cited higher debt leverage and the inadequacy of financial profiles in the electric industry as one of the key factors explaining this deterioration.[74] 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.

As shown on Attachment WEA-8, Value Line expects that the average common equity ratio for the proxy group of western utilities will increase to 55.6% over the next three to five years.

Q. HOW DOES APS' COMMON EQUITY RATIO COMPARE WITH THOSE MAINTAINED BY THE REFERENCE GROUP OF UTILITIES?

A. The 55% common equity ratio requested by APS falls well within the range of capitalizations maintained by the firms in the proxy group at year-end 2004 and is

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[74] See *e.g.*, Standard & Poor's Corporation, "Credit Quality For U.S. Utilities Continues Negative Trend", *RatingsDirect* (Jul. 24, 2003).

entirely consistent with the 55.6% equity ratio based on Value Line's expectations for the proxy group of Western utilities over the near-term.

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A 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 APS' financial risk. For example, payments related to APS' sale and leaseback of its interest in the Palo Verde Unit 2 generating unit, with an initial term of 29.5 years, are akin to those associated with traditional debt financing, and investors also recognize that APS has significant commitments under coal and natural gas commodity and transportation contracts. Because bond ratings agencies and investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.

As discussed earlier, a significant portion of APS' power requirements are obtained through long-term purchased power contracts. Because power purchase agreements ("PPAs") 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. Further, changes in financial accounting standards also result in adjustments that have the effect of further increasing financial leverage. Because bond ratings agencies and investors adjust for these various commitments in their assessment of credit standing, they imply greater risk and reduced financial flexibility.

Q. HOW DO PPAs IMPACT A UTILITY'S FINANCIAL POSITION?

A. When a utility enters into a PPA, the fixed charges associated with the contract increase the utility's financial risk in the same way that long-term debt and other financial obligations increase financial leverage. Under current accounting rules, the accounting for a PPA is not discretionary if the transaction meets specified tests for accounting for capital leases, which require that the obligation be explicitly recorded as a debt obligation on the utility's balance sheet.

As a result, the utility must rebalance its capital structure by increasing its common equity in order to restore its capitalization ratios to previous levels. Since the cost of equity exceeds the cost of debt, this rebalancing imposes additional costs, which are properly considered by regulators.

Q. DO PPAs THAT DO NOT MEET THE ACCOUNTING DEFINITION FOR CAPITAL LEASE TREATMENT STILL IMPACT INVESTORS' ASSESSMENT OF A UTILITY'S FINANCIAL RISKS?

A. Yes. The accounting standards simply reflect the longstanding perception of investors that the fixed obligations associated with PPAs diminish a utility's creditworthiness and financial flexibility. The implications of purchased power commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks.

For example, in reviewing its evaluation of the credit implications of PPAs, S&P affirmed its position that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks.[75] As the rating agency explained:

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[75] Standard & Poor's Corporation, "'Buy Versus Build': Debt Aspects of Purchased Power Agreements," *Utilities & Perspectives* (May 12, 2003).

> [P]urchased power agreements typically result in the assumption of fixed costs representing the portion of the purchase price that is linked to the capacity component of the total payment. These fixed capacity payments are similar to debt service payments incurred by a utility that constructs debt-financed power generation facilities. Therefore, whether a utility builds its own generating plants, or enters into a long-term power purchase agreement with a fixed-cost component, that utility is taking on a financial risk.[76]

When evaluating APS' financial risks, investors likewise recognize that the Company's contractual payment obligations under PPAs are fixed commitments with debt-like characteristics.

In addition to existing agreements, APS has issued a Request for Proposal to provide a total of at least 1,000 MW of summer capacity under long-term contracts. Unless APS takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken the Company's creditworthiness and place downward pressure on its ratings, implying a higher required rate of return for APS' debt and equity securities.[77]

Q. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO APS' PROPOSED CAPITAL STRUCTURE?

A. While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as 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

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[76] Standard & Poor's Corporation, "Prepurchased Power and Its Implications for Public Power Ratings," *RatingsDirect* (Nov. 6, 2003).

[77] 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.

when the company has large capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

The recent decision of S&P and Fitch to downgrade Central Vermont Public Service ("Central Vermont") from triple-B to below investment grade highlights the importance of maintaining sufficient common equity to preserve the utility's creditworthiness, even during times of stress. Despite a common equity ratio that exceeded 60%, S&P and Fitch determined that Central Vermont's financial position was inadequate to support an investment grade rating in the face of an unfavorable regulatory order.[78]

As indicated earlier, the challenges posed by a growing service area, 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' proposed capital structure is just one reflection of the Company's ongoing efforts to preserve its credit standing and maintain access to capital on reasonable

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[78] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (June 14, 2005); "Fitch Ratings Downgrades CVPS," *Business Wire* (Jun. 20, 2005).

terms in order to ensure its ability to meet its obligations to customers. Indeed, Moody's specifically cited the Company's financial policies as support for its decision to revise its credit outlook from "negative" to "stable", concluding that:

> The change in outlook also reflects the company's [APS] demonstrated intent to improve its financial strength by financing a portion of its rising capital expenditures with equity.[79]

Conversely, Moody's also noted that "significant increases in capital expenditures that are financed in a manner inconsistent with the company's historically strong leverage ratios" (i.e., with more debt) could result in a ratings downgrade for APS.[80]

The reasonableness of APS' requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the Company's relative risks and circumstances, the need to support continued system investment, and the imperative of maintaining continuous access to capital, even during times of adverse industry and market conditions. As the experience of Central Vermont illustrates, even a healthy equity cushion may not be sufficient to support a utility's credit ratings when investors perceive a lack of regulatory support.

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO APS' CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that APS' requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. APS' proposed capital structure is in line with

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[79] Moody's Investors Service, "Ratings Action: Arizona Public Service Company," *Global Credit Research* (Apr. 27, 2005).

[80] Moody's Investors Service, "Arizona Public Service Company," *Global Credit Research Credit Opinion* (Apr. 28, 2005).

industry standards, with an equity ratio of approximately 55% being consistent with the average capitalization projected for the proxy group of western electric utilities used to estimate the cost of equity. The reasonableness of this requested capital structure is reinforced by the need to support continued system investment in one of the fastest growing regions in the country. APS' proposed capital structure is just one reflection of the Company's ongoing efforts to enhance its credit standing and maintain access to capital on reasonable terms in order to ensure its ability to meet its obligations to customers.

C. Return on Equity Recommendation

Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR ROE FOR APS?

A. As explained earlier, based on the various capital market oriented analyses described in my testimony, and after incorporating an adjustment for flotation costs, I concluded that the fair rate of return on equity range for the electric utility proxy group was 11.0% to 12.0%. 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 the middle of this range, or approximately 11.5%, represents a fair and reasonable ROE for APS.

Q. IF THE ACC WERE TO REPEAL OR SUBSTANTIALLY MODIFY THE PSA MECHANISM FOR APS, WOULD THAT HAVE AN IMPACT ON THE COST OF EQUITY?

A. Most definitely. Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to the uncertainties imposed by power market volatility has increased dramatically. S&P noted early on that without a mechanism to regularly adjust rates, escalating commodity prices could

create significant financial damage for retail service providers. S&P regards the lack of a PSA as one of the greatest impediments to financial stability:

> One of the most significant threats today to utilities' credit quality is uncertainty about the timely ability to pass power costs on to consumers. The issue for Standard & Poor's is this: To what lengths are regulators prepared to go to shelter ratepayers from the vagaries of the market and thereby threaten the financial strength of the utilities? ... To preserve credit quality, these companies must be able to adjust rates not just to cover the cost of procuring power, but also to deliver the appropriate price signals to consumers.[81]

Investors' required rates of return for utilities are premised on the regulatory compact that allows the utility an opportunity to recover reasonable and necessary costs. By sheltering utilities from exposure to extraordinary power cost volatility through a PSA, customers benefit from lower capital costs than they would otherwise bear. Of course, the corollary implies that shifting the burden of extraordinary risks to shareholders would have the effect of considerably increasing the cost of equity to APS, with the end-result being a greater cost of utility service to customers.

Q. WHAT COST OF EQUITY WOULD BE IMPLIED FOR APS IF THE PSA WAS REPEALED OR SUBSTANTIALLY NARROWED IN SCOPE?

A. Denying APS the ability to recover future power supply costs through a PSA mechanism would imply a significant increase in its investment risks relative to the proxy group of utilities used to estimate the cost of equity. Thus, if the ACC were to repeal, or substantially narrow the scope of the PSA, a higher rate of return on equity would be required to compensate investors for bearing the greater risks of energy market volatility. Moreover, given renewed focus on the importance of

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[81] Standard & Poor's, "California Aside, Regulatory Support for Utility Credit Quality Remains Intact", *RatingsDirect*, p. 2 (Jul. 13, 2001).

regulatory consistency and predictability, any renegotiation of a PSA mechanism that is already perceived as relatively weak by the investment community would send an alarming message that could impact the cost of capital for all Arizona utilities. Considering the investment community's increased sensitivity to such asymmetric risks, a rate of return on equity from at least the very top of my reasonable range, or 12%, would be warranted.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

QUALIFICATIONS OF WILLIAM E. AVERA

I received a B.A. degree with a major in economics from Emory University. After serving in the United States 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 in 1979, 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, as well as the Federal Communications Commission, 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 over 30 states.

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 also have 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 also have served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

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Economic and Financial Counsel

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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 100 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 200 cases before regulatory agencies addressing cost of capital, 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, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wisconsin.

Testified in over 30 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (over 60 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 Governor George Bush and Public Utility Commission of Texas; 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 (SEAL) 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

EXPECTED DIVIDEND YIELD

Company	Recent Price (a)	Estimated Dividends Next 12 Mos. (a)	Dividend Yield
Black Hills Corp.	$ 42.02	$ 1.31	3.1%
Edison International	$ 45.55	$ 1.10	2.4%
Hawaiian Electric	$ 27.23	$ 1.24	4.6%
IDACORP, Inc.	$ 29.18	$ 1.20	4.1%
MDU Resources Group	$ 35.03	$ 0.76	2.2%
PNM Resources Group	$ 28.08	$ 0.80	2.8%
Pinnacle West Capital	$ 43.59	$ 1.96	4.5%
Puget Energy, Inc.	$ 22.47	$ 1.00	4.5%
Sempra Energy	$ 44.87	$ 1.18	2.6%
Xcel Energy	$ 18.98	$ 0.87	4.6%
Average			**3.5%**

(a) The Value Line Investment Survey, Summary and Index (Oct. 14, 2005).

CONSTANT GROWTH DCF MODEL

PROJECTED GROWTH RATES

	Earnings				
	(a)	(b)	(c)	(d)	(e)
Company	IBES	Value Line	First Call	Zacks	Reuters
Black Hills Corp.	5.0%	2.5%	5.0%	6.0%	5.0%
Edison International	7.0%	7.0%	6.5%	7.5%	8.0%
Hawaiian Electric	3.0%	2.5%	3.0%	3.5%	2.6%
IDACORP, Inc.	4.0%	6.0%	4.0%	4.3%	4.2%
MDU Resources Group	7.0%	8.5%	7.5%	7.7%	6.6%
PNM Resources Group	11.0%	8.0%	12.0%	7.7%	12.0%
Pinnacle West Capital	5.0%	3.5%	4.5%	5.2%	4.6%
Puget Energy, Inc.	4.0%	5.5%	4.0%	4.8%	4.6%
Sempra Energy	5.0%	3.5%	5.0%	5.9%	5.6%
Xcel Energy	3.0%	7.5%	3.0%	4.2%	4.0%
Average	**5.4%**	**5.5%**	**5.5%**	**5.7%**	**5.7%**

NA -- Not Available

(a) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (Oct. 2005).
(b) The Value Line Investment Survey (Aug. 12, 2005).
(c) First Call Earnings Estimates from www.finance.yahoo.com (Oct. 3, 2005).
(d) Zacks Investment Research growth estimates from www.zacks.com (Oct. 3, 2005).
(e) Reuters earnings growth rates from www.investor.reuters.com (Oct. 3, 2005).

CONSTANT GROWTH DCF MODEL

SUSTAINABLE GROWTH RATE

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections 2008-10			2004		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
Black Hills Corp.	$2.25	$1.44	$26.25	$22.43	3.2%	1.0157	36.0%	8.7%	3.1%	0.12%	3.3%
Edison International	$2.45	$1.40	$24.15	$18.57	5.4%	1.0263	42.9%	10.4%	4.5%	0.01%	4.5%
Hawaiian Electric	$1.75	$1.24	$17.25	$15.01	2.8%	1.0139	29.1%	10.3%	3.0%	0.03%	3.0%
IDACORP, Inc.	$2.10	$1.20	$28.10	$23.88	3.3%	1.0163	42.9%	7.6%	3.3%	0.06%	3.3%
MDU Resources Group	$2.50	$0.90	$22.25	$14.09	9.6%	1.0457	64.0%	11.7%	7.5%	1.17%	8.7%
PNM Resources Group	$1.95	$1.09	$23.25	$18.19	5.0%	1.0245	44.1%	8.6%	3.8%	0.38%	4.2%
Pinnacle West Capital	$3.15	$2.33	$37.25	$32.14	3.0%	1.0148	26.0%	8.6%	2.2%	0.30%	2.5%
Puget Energy, Inc.	$1.75	$1.12	$19.50	$16.24	3.7%	1.0183	36.0%	9.1%	3.3%	0.33%	3.6%
Sempra Energy	$4.00	$1.32	$33.75	$20.78	10.2%	1.0485	67.0%	12.4%	8.3%	0.95%	9.3%
Xcel Energy	$1.50	$1.05	$15.25	$12.99	3.3%	1.0160	30.0%	10.0%	3.0%	0.66%	3.7%
Average											**4.6%**

(a) The Value Line Investment Survey (Aug. 12, 2005).
(b) Annual growth in book value per share from 2004 to 2008-10.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (EPS/2008-10 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).

AUTHORIZED RATES OF RETURN – CURRENT YIELD

YEAR	(a) ALLOWED ROE	(b) AVERAGE PUBLIC UTILITY BOND YIELD	RISK PREMIUM
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.14%	3.29%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.50%	3.66%
2003	10.97%	6.61%	4.36%
2004	10.73%	6.20%	4.53%
Average		9.59%	3.17%

Regression Output	
Constant	0.07299
Std Err of Y Est	0.00557
R Squared	0.79192
No. of Observations	31
Degrees of Freedom	29
X Coefficient(s)	-0.43083
Std Err of Coef.	0.04101

Current Equity Risk Premium	
Avg. Yield over Study Period	9.59%
Aug. 2005 Avg. Utility Bond Yield (c)	5.51%
Change in Bond Yield	-4.08%
Risk Premium/Interest Rate Relationship	-43.08%
Adjustment to Average Risk Premium	1.76%
Average Risk Premium over Study Period	3.17%
Adjusted Risk Premium	4.93%

(a) Regulatory Research Associates, Major Rate Case Decisions, January 1990 - December 2004, *Regulatory Focus* (January 2005); Major Rate Case Decisions, *Regulatory Focus*, (January 16, 1990); Argus, *UtilityScope Regulatory Service* (January 1986).

(b) Moody's *Public Utility Manual* (2003); Moody's *Credit Perspectives* (various editions); Mergent *Bond Record* (various editions).

(c) Moody's *Credit Perspectives* (Oct. 3, 2005).

AUTHORIZED RATES OF RETURN -- 2006 YIELD

YEAR	(a) ALLOWED ROE	(b) AVERAGE PUBLIC UTILITY BOND YIELD	RISK PREMIUM
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.14%	3.29%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.50%	3.66%
2003	10.97%	6.61%	4.36%
2004	10.73%	6.20%	4.53%
Average		9.59%	3.17%

Regression Output	
Constant	0.07299
Std Err of Y Est	0.00557
R Squared	0.79192
No. of Observations	31
Degrees of Freedom	29
X Coefficient(s)	-0.43083
Std Err of Coef.	0.04101

Current Equity Risk Premium	
Avg. Yield over Study Period	9.59%
2006 Avg. Utility Bond Yield (c)	6.80%
Change in Bond Yield	-2.79%
Risk Premium/Interest Rate Relationship	-43.08%
Adjustment to Average Risk Premium	1.20%
Average Risk Premium over Study Period	3.17%
Adjusted Risk Premium	4.37%

(a) Regulatory Research Associates, Major Rate Case Decisions, January 1990 - December 2004, *Regulatory Focus* (January 2005); Major Rate Case Decisions, *Regulatory Focus*, (January 16, 1990); Argus, *UtilityScope Regulatory Service* (January 1986).

(b) Mergent *Public Utility Manual* (2003); Moody's *Credit Perspectives* (various editions); Mergent *Bond Record* (various editions).

(c) Projected yield on public utility bonds for 2006 based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 25-Year Focus* (First Quarter 2005), EIA, *Annual Energy Outlook* (2005), and Blue Chip Financial Forecasts (Sep. 1, 2005).

RISK PREMIUM APPROACH

REALIZED RATES OF RETURN

	S&P ELECTRIC UTILITIES (a)			AVERAGE PUBLIC UTILITY BONDS (b)		
	CLOSE PRICE	DIV	ANNUAL REALIZED RETURN	CLOSE YIELD	PRICE	ANNUAL REALIZED RETURN
1945	$16.34		(c)	2.79%		(d)
1946	$15.53	$0.73	-0.49%	2.77%	$100.36	3.15%
1947	$12.89	$0.75	-12.17%	3.02%	$95.66	-1.57%
1948	$12.37	$0.71	1.47%	3.06%	$99.31	2.33%
1949	$14.60	$0.80	24.49%	2.79%	$104.81	7.87%
1950	$14.49	$0.88	5.27%	2.87%	$98.59	1.38%
1951	$16.07	$0.92	17.25%	3.24%	$93.73	-3.40%
1952	$18.28	$0.95	19.66%	3.19%	$100.85	4.09%
1953	$18.97	$0.99	9.19%	3.37%	$96.99	0.18%
1954	$22.39	$1.03	23.46%	3.10%	$104.65	8.02%
1955	$24.06	$1.09	12.33%	3.31%	$96.47	-0.43%
1956	$23.61	$1.13	2.83%	3.93%	$90.24	-6.45%
1957	$24.85	$1.19	10.29%	4.29%	$94.54	-1.53%
1958	$33.14	$1.24	38.35%	4.39%	$98.50	2.79%
1959	$33.42	$1.30	4.77%	4.86%	$93.28	-2.33%
1960	$39.35	$1.37	21.84%	4.58%	$104.12	8.98%
1961	$49.28	$1.44	28.89%	4.62%	$99.41	3.99%
1962	$48.60	$1.52	1.70%	4.41%	$103.14	7.76%
1963	$51.97	$1.63	10.29%	4.49%	$98.81	3.22%
1964	$58.21	$1.74	15.36%	4.54%	$99.26	3.75%
1965	$58.05	$1.90	2.99%	4.82%	$95.98	0.52%
1966	$53.49	$2.04	-4.34%	5.65%	$89.03	-6.15%
1967	$49.90	$2.16	-2.67%	6.57%	$88.85	-5.50%
1968	$51.95	$2.27	8.66%	6.85%	$96.69	3.26%
1969	$42.65	$2.33	-13.42%	8.39%	$84.09	-9.06%
1970	$45.62	$2.40	12.59%	8.45%	$99.38	7.77%
1971	$44.18	$2.47	2.26%	7.92%	$105.70	14.15%
1972	$43.50	$2.53	4.19%	7.48%	$104.91	12.83%
1973	$32.85	$2.51	-18.71%	8.17%	$92.74	0.22%
1974	$22.03	$2.49	-25.36%	10.02%	$83.23	-8.60%
1975	$30.56	$2.57	50.39%	9.87%	$101.38	11.40%
1976	$35.17	$2.58	23.53%	8.61%	$112.78	22.65%
1977	$35.67	$2.74	9.21%	8.65%	$99.60	8.21%
1978	$31.38	$2.94	-3.78%	9.67%	$90.50	-0.85%
1979	$28.44	$3.10	0.51%	11.68%	$83.88	-6.45%
1980	$27.19	$3.20	6.86%	14.48%	$81.32	-7.00%
1981	$29.33	$3.42	20.45%	15.77%	$92.03	6.51%
1982	$36.15	$3.62	35.59%	13.55%	$115.70	31.47%
1983	$37.14	$3.84	13.36%	13.48%	$100.50	14.05%
1984	$42.26	$4.06	24.72%	12.96%	$103.82	17.30%
1985	$48.82	$4.15	25.34%	10.82%	$118.26	31.22%
1986	$58.31	$4.21	28.06%	8.96%	$118.33	29.15%
1987	$49.78	$4.34	-7.19%	10.99%	$82.89	-8.15%
1988	$53.87	$4.37	16.99%	10.02%	$108.79	19.78%
1989	$66.55	$4.28	31.48%	9.31%	$106.80	16.82%
1990	$63.47	$4.45	2.06%	9.57%	$97.56	6.87%
1991	$77.25	$4.57	28.91%	8.76%	$108.11	17.68%
1992	$76.78	$4.68	5.45%	8.36%	$104.14	12.90%
1993	$81.71	$4.71	12.56%	7.33%	$111.65	20.01%
1994	$66.30	$4.65	-13.17%	8.79%	$85.41	-7.26%
1995	$81.62	$4.67	30.15%	7.21%	$118.07	26.86%
1996	$76.75	$4.61	-0.32%	7.58%	$95.90	3.11%
1997	$91.49	$4.47	25.03%	7.16%	$104.82	12.40%
1998	$100.86	$4.39	15.04%	6.84%	$103.78	10.94%
1999	$77.42	$4.35	-18.93%	8.04%	$87.23	-5.93%
2000	$113.00	$4.42	51.67%	7.79%	$102.72	10.76%
2001	$99.70	$3.56	-8.62%	7.86%	$99.24	7.03%
2002	$77.85	$3.88	-18.02%	7.13%	$108.41	16.27%
2003	$92.63	$3.47	23.45%	6.35%	$109.60	17.46%
2004	$112.82	$3.67	25.75%	5.93%	$105.40	12.53%
AVERAGE 1946-2004			10.81%			6.76%

REALIZED RATE OF RETURN	
S&P ELECTRIC UTILITIES	10.81%
PUBLIC UTILITY BONDS	6.76%
EQUITY RISK PREMIUM	4.04%

(a) S&P's *Security Price Index Record* (2002), *The Analysts' Handbook* (1967, 1999, 2001, 2004, Monthly Supplement April 2005).
(b) Average public utility bond yields for December from Mergent *Public Utility Manual* (2003), Mergent *Bond Record* (Feb. 2005).
(c) Computed by adding gain or loss (ending stock price - beginning stock price) to annual dividends and dividing by beginning stock price.
(d) Computed as sum of capital gain or loss plus interest income, divided by beginning price.

CAPITAL ASSET PRICING MODEL

FORWARD-LOOKING RISK PREMIUM - CURRENT ESTIMATE

Market Rate of Return		
Dividend Yield (a)	2.1%	
Growth Rate (b)	11.4%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.5%
Market Risk Premium (e)		9.0%
Utility Proxy Group Beta (f)		0.89
Utility Proxy Group Risk Premium (g)		8.0%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.5%
Implied Cost of Equity (h)		**12.5%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Oct. 7, 2005).
(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* (Sep. 2005) and www.valueline.com (Oct. 7, 2005).
(c) (a) + (b)
(d) Average of the daily yields on 20-year Treasury bonds for September 2005 reported by the U.S. Department of the Treasury at www.treas.gov.
(e) (c) - (d).
(f) The Value Line Investment Survey (Aug. 12, 2005).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

FORWARD-LOOKING RISK PREMIUM - RATE YEAR ESTIMATE

Market Rate of Return		
Dividend Yield (a)	2.1%	
Growth Rate (b)	11.4%	
Market Return (c)		13.5%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		5.5%
Market Risk Premium (e)		8.0%
Utility Proxy Group Beta (f)		0.89
Utility Proxy Group Risk Premium (g)		7.1%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		5.5%
Implied Cost of Equity (h)		**12.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Oct. 7, 2005).

(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* (Sep. 2005) and www.valueline.com (Oct. 7, 2005).

(c) (a) + (b)

(d) Projected yield on 20-year Treasury bonds for 2006 based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 25-Year Focus* (First Quarter 2005), Energy Information Administration, *Annual Energy Outlook* (2005), and Blue Chip Financial Forecasts (Sep. 1, 2005).

(e) (c) - (d).

(f) The Value Line Investment Survey (Aug. 12, 2005).

(g) (e) x (f).

(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

HISTORICAL RISK PREMIUM - CURRENT ESTIMATE

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.2%
Utility Proxy Group Beta (b)	0.89
Utility Proxy Group Risk Premium (c)	6.4%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	4.5%
Implied Cost of Equity (e)	**10.9%**

(a) Arithmetic mean return on Large Company Stocks from 1926-2004 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2005 Yearbook*, at 81.
(b) The Value Line Investment Survey (Aug. 12, 2005).
(c) (a) x (b).
(d) Average of the daily yields on 20-year Treasury bonds for September 2005 reported by the U.S. Department of the Treasury at www.treas.gov.
(e) (c) + (d).

CAPITAL ASSET PRICING MODEL

HISTORICAL RISK PREMIUM - RATE YEAR ESTIMATE

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.2%
Utility Proxy Group Beta (b)	0.89
Utility Proxy Group Risk Premium (c)	6.4%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	5.5%
Implied Cost of Equity (e)	**11.9%**

(a) Arithmetic mean return on Large Company Stocks from 1926-2004 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2005 Yearbook*, at 81.

(b) The Value Line Investment Survey (Aug. 12, 2005).

(c) (a) x (b).

(d) Projected yield on 20-year Treasury bonds for 2006 based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 25-Year Focus* (First Quarter 2005), Energy Information Administration, *Annual Energy Outlook* (2005), and Blue Chip Financial Forecasts (Sep. 1, 2005).

(e) (c) + (d).

PROXY GROUP CAPITAL STRUCTURE

	At December 31, 2004 (a)			Value Line Projected 2008-10 (b)		
Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
Black Hills Corp.	50.3%	0.5%	49.2%	43.0%	0.5%	56.5%
Edison International	61.3%	1.6%	37.2%	51.5%	1.5%	47.0%
Hawaiian Electric	48.4%	1.4%	50.2%	45.0%	1.0%	54.0%
IDACORP, Inc.	51.2%	0.0%	48.8%	47.0%	0.0%	53.0%
MDU Resources Group	36.0%	0.6%	63.4%	23.5%	0.0%	76.5%
PNM Resources Group	47.1%	0.5%	52.4%	48.5%	0.5%	51.0%
Pinnacle West Capital	52.0%	0.0%	48.0%	45.0%	0.0%	55.0%
Puget Energy, Inc.	54.1%	6.8%	39.1%	56.5%	0.5%	43.0%
Sempra Energy	34.2%	0.0%	65.8%	31.0%	1.5%	67.5%
Xcel Energy	55.8%	0.9%	43.3%	47.5%	0.5%	52.0%
Average	**49.0%**	**1.2%**	**49.7%**	**43.9%**	**0.6%**	**55.6%**

(a) Company Form 10-K and Annual Reports.

(b) The Value Line Investment Survey (Aug. 12, 2005).

EXHIBIT
APS 42
admitted

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF

WILLIAM E. AVERA

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

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REBUTTAL TESTIMONY OF WILLIAM E. AVERA

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. ARE YOU THE SAME WILLIAM E. AVERA THAT PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My purpose here is to respond to the testimony submitted by David C. Parcell, on behalf of the Staff of the Arizona Corporation Commission ("ACC" or "the Commission"), and Mr. Stephen G. Hill, on behalf of the Residential Utility Consumer Office ("RUCO"), concerning a fair rate of return on equity ("ROE") for Arizona Public Service Company ("APS" or "the Company"). I also address Mr. Hill's position concerning the reasonableness of APS' requested capital structure. In addition, I demonstrate the need for an attrition adjustment to the allowed return to give APS an opportunity to actually earn the ROE authorized by the Commission.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. After summarizing my conclusions in Section II, Section III of my Rebuttal Testimony examines the reasonableness of the ROE recommendations of Mr. Parcell and Mr. Hill against objective benchmarks. In particular, their

recommendations are shown to be inadequate to meet the economic standards under accepted regulatory policy. Next, Sections IV and V address the specific shortcomings of Mr. Parcell's and Mr. Hill's analyses and explain how their methods impart a downward bias to their recommendations. Finally, Section VI addresses the problem of attrition and evaluates the need for an attrition adjustment to ensure that the economic requirements for a fair rate of return will be met.

II. SUMMARY

Q. WHAT ARE YOUR CONCLUSIONS REGARDING STAFF'S AND RUCO'S ROE RECOMMENDATIONS?

A. Both Mr. Parcell and Mr. Hill purport to estimate the return investors require to put their money in APS. Each recognizes that investors have many potential options for their funds, and APS must compete for investment dollars. As documented in my Rebuttal Testimony, the 10.25% ROE recommendation of Mr. Parcell is significantly downward-biased and Mr. Hill's 9.25% cost of equity is completely out of touch with the requirements of actual investors in the capital markets. My rebuttal details the shortcomings that lead Mr. Parcell and Mr. Hill to underestimate investor requirements. Moreover, I document that application of quantitative methods identical to those recently used by the ACC Staff and adopted by this Commission imply an ROE of 11.20% for APS before consideration of flotation costs.

In addition, while Mr. Parcell accepts APS' requested capital structure, Mr. Hill would combine his low ROE with a capital structure with less equity than APS actually maintains. This phantom capital structure makes RUCO's position more extreme and amplifies the financial damage implied by Mr. Hill's recommendations. My Rebuttal Testimony demonstrates that Mr. Hill's rationale

for adjusting the capital structure is based on false premises and is inconsistent with industry practice and rating agency requirements.

But aside from the plethora of technical arguments, their recommendations do not withstand a simple reality check. These witnesses recommend returns lower than other utilities are currently authorized, a fact clearly documented in their own sources. As I also document in this testimony, both witnesses recommend that the ACC allow APS a return below the average that other commissions have been allowing utilities in recent months. Yet compared to other utilities, APS is facing unique risks and challenges such as a weakened credit standing, substantial funding needs, exposure to regulatory lag and increasing costs. Providing APS with the opportunity to earn a return that reflects these realities is an essential ingredient to strengthen the Company's financial position, which ultimately benefits customers by ensuring the Company's continued ability to meet customers' needs at lower long-run costs. The Staff and RUCO recommendations are out of line with investor requirements and regulatory practice and adopting them would send an alarming signal to the investment community at this critical juncture for APS. If investors lose confidence in the Company, customers and the economy of Arizona would be the ultimate losers.

Aside from their low return on equity recommendations, there is a more fundamental flaw in the testimonies of Mr. Parcell and Mr. Hill. Both witnesses agree that sound economics and the *Hope* and *Bluefield* cases require that the end result of return recommendations be tested against the standards of maintaining financial integrity, access to capital, and adequate compensation for risk. Even if the methods they use to test the end results were correct (and my rebuttal demonstrates that they are not), both witnesses wrongly assume that APS will

actually earn their allowed return recommendation. In fact, attrition will prevent APS from having an opportunity to actually earn the allowed ROE. Indeed, SFR Schedule F-1 of APS' January 31, 2006 filing ("Schedule F1") demonstrates that even if the Company were allowed my recommended 11.5%, and the new rates became effective on January 1, 2007, the earned return for 2007 would fall to 9.8%.

As explained in the Rebuttal Testimonies of Mr. Brandt and Mr. Wheeler and later in my rebuttal, the relentless forces of growth, new capital investment, inflation, and unrecovered costs, combined with regulatory lag, will drive APS' earned return well below the allowed ROE. Investors focus on what will actually be earned, not the promise of an allowed return that will be eroded by attrition. As a result, the financial indicators calculated by Mr. Parcell and Mr. Hill that assumed their recommended return is actually earned are exercises in financial fiction – they have no meaning in the real world from which capital must be raised. My Rebuttal Testimony proposes an attrition adjustment to the ROE of at least 170 basis points to give APS some opportunity to maintain its financial integrity, preserve the ability to attract capital, and offer investors a return commensurate with risk.

Q. WHAT DO TRENDS IN CAPITAL COSTS INDICATE WITH RESPECT TO YOUR RECOMMENDED 11.5% ROE FOR APS?

A. Since the time my Direct Testimony was prepared, capital costs have trended upwards. During the intervening period, the Federal Reserve Board ("Fed") continued its credit tightening campaign through a policy of measured increases to the target federal funds rate. Coupled with increasing concerns over inflation and other political and economic considerations, this has translated into higher long-

term capital costs. As shown in the table below, long-term bond yields have risen significantly from the levels referenced in my Direct Testimony:

	BBB Utility	20-Yr Govt.
July 2006	6.61%	5.25%
Avera Direct	5.80%	4.50%
Increase	0.81%	0.75%

While the cost of equity does not move in lockstep with changes in interest rates, the fact that long-term bond yields have increased significantly since my analyses were prepared indicates that my 11.5% recommended ROE is a conservative estimate of investors' current required rate of return.[1] Assuming that the cost of equity changes about one-half as much as the change in interest rates, a 75 basis point increase in bond yields implies an upward adjustment to the cost of equity on the order of approximately 33 basis points.[2] Coupled with the imperative of buttressing the Company's credit standing and meeting the economic requirements specified for a fair rate of return, this provides further confirmation that the 11.5% ROE requested by APS is the minimum cost of equity that could be found reasonable and should be adopted.

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[1] Other factors also suggest that the cost of equity for my proxy group has increased. For example, the current beta values for my proxy companies shown on Attachment WEA-3RB result in a group average of 0.97, versus the 0.89 reflected in my CAPM analyses. Also, the cost of equity indicated by my DCF analyses has increased since my Direct Testimony was filed.

[2] The inverse relationship between equity risk premiums and interest rates was discussed in my Direct Testimony at 45-46.

III. REASONABLENESS OF RETURN

Q. DR. AVERA, IS IT POSSIBLE TO DISTILL THE MANY COMPLEXITIES ASSOCIATED WITH ESTIMATING INVESTORS' REQUIRED RATE OF RETURN INTO A SINGLE, THRESHOLD ISSUE?

A. While the details underlying a determination of the cost of equity are all near and dear to my heart, there is one fundamental requirement that any ROE recommendation must satisfy before it can be considered reasonable. Competition for capital is intense, and utilities such as APS must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of equivalent risk if they are to maintain their financial flexibility and ability to attract capital.

Beyond the specific quantitative analyses that I present in detail in subsequent sections demonstrating how Mr. Parcell and Mr. Hill underestimated the cost of equity, the bottom line is, "Do Mr. Parcell's and Mr. Hill's ROE recommendations meet the threshold test of reasonableness required by established regulatory and economic standards governing a fair rate of return on equity?" Based on the evidence discussed subsequently, the answer is clearly, "No."

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING APS' ACCESS TO CAPITAL?

A. Considering investors' heightened awareness of the risks associated with the electric power industry, supportive regulation remains crucial in preserving APS' access to capital. Moreover, considering the traumatic events that have transpired since the third quarter of 2000, investors' sensitivity to market and regulatory uncertainties has increased dramatically. Capital markets recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

For example, the decision of Standard & Poor's Corporation ("S&P") and Fitch Ratings ("Fitch") to downgrade Central Vermont from triple-B to below investment grade highlights the importance of constructive regulation. In explaining its rationale, S&P and Fitch cited an unfavorable rate order by the Vermont Public Service Board. S&P concluded that:

> The rate order represents an adverse shift in the company's regulatory environment, which heightens its business risk for the foreseeable future. ... It also limits the company's ability to generate adequate and stable cash flows over the foreseeable future. To be considered highly creditworthy, a utility with a marginal financial profile must operate in a regulatory environment that provides for financial stability.[3]

Business Wire reported to investors that Central Vermont "will now have to provide cash collateral for some power supply arrangements" and pay "increased financing costs for debt," with the end result being "higher customer costs."[4] As the investment advisory publication referenced by Mr. Hill made clear, "downgrades imply not only higher borrowing costs but also carry a negative psychological impediment toward new investment."[5]

Q. DO YOU AND MESSRS. PARCELL AND HILL ALL AGREE THAT A UTILITY'S ABILITY TO ATTRACT CAPITAL MUST BE CONSIDERED IN ESTABLISHING A FAIR RATE OF RETURN?

A. Yes. Mr. Parcell and Mr. Hill both recognized clearly the fundamental standards underlying a determination of a fair rate of return on equity. For example, Mr. Hill observed that investors should have "an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in

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[3] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (Jun. 14, 2005).

[4] *Id.*

[5] A.G. Edwards, "Gas Utilities Quarterly Review," April 6, 2006 at 9.

the unregulated sector for assuming the same degree of risk."[6] Both Mr. Parcell (p. 6-7) and Mr. Hill (p. 4) acknowledged the Supreme Court's *Bluefield* and *Hope* decisions, which established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence that, if the utility is efficient and prudent on a prospective basis, it will have the opportunity to provide returns commensurate with those expected for other investments of comparable risk.

Q. WHAT BENCHMARKS ARE USEFUL IN EVALUATING THE ABILITY OF STAFF'S AND RUCO'S ROE RECOMMENDATIONS TO MEET THIS FUNDAMENTAL REGULATORY REQUIREMENT?

A. Reference to allowed rates of return for other utilities provides one useful guideline that can be used to assess the extent to which their respective 10.25% and 9.25% ROE recommendations are comparable and sufficient. The rates of return on common equity authorized electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates ("RRA") and published in its *Regulatory Focus* report. RRA reported average authorized ROEs of 10.69% and 10.57% for electric utilities for the second quarter and year-to-date 2006, respectively. APS must compete with other utilities for the large amounts of capital needed to fund growth and infrastructure improvements in Arizona. It is unreasonable to suppose that in the face of rising capital costs during 2006, investors would be attracted by the Staff and RUCO's recommendations for APS, which fall significantly below the allowed returns for other utilities.

As shown on Attachment WEA-1RB, with respect to the group of twelve utilities other than Pinnacle West that Mr. Hill concluded were most comparable to APS, data from the June 2006 *AUS Monthly Utility Report* (a source relied on by Mr. Hill

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[6] Hill Direct at 4.

and Mr. Parcell)[7] indicated that these firms are presently authorized an average rate of return on equity of 10.89%, or 164 basis points more than Mr. Hill's ROE recommendation. Similarly, this source reported an average authorized ROE for the utilities in Mr. Parcell's comparable group (excluding Pinnacle West) of 10.91%, which exceeds his recommended ROE by 66 basis points.

Q. WHAT OTHER BAROMETERS INDICATE THAT INTERVENORS' ROE RECOMMENDATIONS ARE INSUFFICIENT TO ALLOW APS TO ATTRACT CAPITAL?

A. The comparable earnings standard recognizes that APS must compete for capital against firms in its own industry. Value Line reports that electric utilities as a whole are anticipated to earn a return of 11.5% from 2007 through 2011.[8] A return that is significantly below the 11.5% that Value Line expects for electric utilities generally would undermine confidence in the financial integrity of the firm and its ability to attract capital. Meanwhile, Mr. Hill expects the companies in his reference group to earn 10.35% on equity,[9] while myopically arguing that APS, which he claims is comparable in risk, could attract capital with a return of 9.25%.

Q. DO CUSTOMERS ALSO BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. While providing an ROE that is sufficient to maintain APS' ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. 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

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[7] Hill Direct at Schedule 2, p. 4 and Schedule 3; Parcell Direct at Schedule 7.

[8] The Value Line Investment Survey (Sep. 1, 2006).

[9] Hill Direct at Schedule 10.

take whatever actions are required to ensure a reliable electric supply. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised. To continue to meet potential challenges successfully and economically, it is crucial that APS receive adequate support for its credit standing.

Q. WHAT ARE THE POTENTIAL CONSEQUENCES OF AUTHORIZING A RATE OF RETURN LESS THAN WHAT IS REQUIRED TO MEET THE FINANCIAL END-RESULT TEST?

A. Failing to provide investors with the opportunity to earn an adequate rate of return will only serve to hamper the Company's efforts to bolster its financial position, while impeding APS' ability to attract the capital needed to meet the economic and reliability needs of its service area. Given that the Company's financial parameters and bond ratings are already under pressure, and considering the significant risks faced by APS, the perception of a lack of regulatory support will almost certainly lead to ratings downgrades.

S&P recently confirmed this assessment, noting that "[t]he outcome in the case will largely determine whether APS' financial condition will improve from its currently weak position."[10] Similarly, Moody's concluded that the "key credit concern is the need for rate increases in a challenging regulatory environment in Arizona, which is expected to contribute to financial ratios that are weak for the rating category over the near term."[11] Setting an ROE that fails to provide investors with an opportunity to earn returns commensurate with companies of comparable risk

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[10] Standard & Poor's Company, Bulletin: ACC Staff Recommendation Has No Immediate Effect On Arizona Public Service Co. Rtg," *RatingsDirect* (Aug. 22, 2006).

[11] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Global Credit Research* (May 9, 2006).

would weaken APS' financial integrity, violate the capital attraction standard, and send the wrong signal to investors at a time when access to capital markets is crucial for the Company.

Q. BASED ON YOUR REVIEW, WHAT DID YOU CONCLUDE WITH RESPECT TO THE REASONABLENESS OF STAFF AND RUCO'S RECOMMENDATIONS?

A. My review of authorized and earned rates of return conclusively demonstrates that the ROE recommendations of Mr. Parcell and Mr. Hill do not provide APS with the opportunity to earn a competitive rate of return on equity, commensurate with those that investors expect for other utilities. Moreover, the downward-biased ROEs of Staff and RUCO would further weaken APS' credit standing and ability to attract capital and almost certainly lead to ratings downgrades. Simply put, APS is facing large capital needs and has bond ratings at the lower extreme of the industry. If this Commission were to order a return at the lower end of the range of what other utilities are authorized and investors expect them to actually earn, why would investors supply capital to APS rather than other utilities? When investors factor in the likelihood that attrition will cause APS' actual returns to fall short of the allowed return, adopting Mr. Parcell's 10.25% return would not be sufficient to attract capital. Mr. Hill's 9.25% falls even further below any notion of reasonableness.

IV. DAVID C. PARCELL

Q. HOW DID MR. PARCELL ARRIVE AT HIS RECOMMENDED ROE OF 10.25% FOR APS?

A. Mr. Parcell's recommendation was based on the results of his application of the constant growth DCF model, CAPM, and comparable earnings approaches. His analyses focused primarily on a seven-company reference group, identified based

on Mr. Parcell's application of six separate selection criteria, as well as the ten companies in my proxy group. Mr. Parcell concluded that his DCF application implied a cost of equity in the range of 9% to 10%, his CAPM range was 10.5% to 10.75%, and he found a 10% cost of equity under his comparable earnings analysis. By focusing "on the upper portions of the respective model results," Mr. Parcell determined a cost of equity range of 9.5% to 10.75%, and recommended a point estimate of 10.25%.

Q. DO YOU AGREE WITH THE CRITERIA MR. PARCELL USED TO DEFINE HIS PROXY GROUP?

A. No. Mr. Parcell eliminated all utilities with less that 50% of operating revenues from regulated electric operations. But as discussed in greater detail subsequently in response to Mr. Hill, under the regulatory standards established by *Hope* and *Bluefield*, the issue in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream. Mr. Parcell presented no evidence that there is a connection between the subjective revenue test that he employed and the risk perceptions of actual investors in the capital markets. Moreover, because of organizational structure and reporting conventions, it is not always possible to accurately quantify revenues attributable to electric utility operations.

Finally, while Mr. Parcell included only firms that were rated triple-B by Moody's and S&P in his reference group, he applied his criteria using senior debt ratings, not the corporate, or issuer credit rating for the utility as a whole. Because equity investors are focused on the overall investment risks of the firm, and not those attributable to a specific debt issue, the appropriate indicia is the corporate credit rating.

A. DCF Analysis

Q. PLEASE DESCRIBE MR. PARCELL'S APPLICATION OF THE DCF MODEL.

A. For each of the firms in his reference group, Mr. Parcell calculated a dividend yield by dividing the company's current annualized dividend ("D_0"), increased by one-half the expected growth rate, by the average stock price for the three months ended July 2006. With respect to the growth component, Mr. Parcell averaged five proxies for investors' expectations that focused on historical and projected growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"), as well as the sustainable, or retention growth calculated as the product of the firm's retention ratio ("b") and its earned return on book equity ("r").

Combining this average growth rate with his adjusted spot dividend yield resulted in cost of equity estimates ranging from 7.5% to 8.8%, with the average being 8.1% and a median of 8.4%. Using the projected EPS growth rates published by First Call, Mr. Parcell also reported a high value of 10.0% for his reference group. Mr. Parcell concluded that "a range of 9 percent to 10 percent represents the current DCF cost of equity for APS,"[12] although only the high values produced by his analysis fall within this range.[13]

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[12] Parcell Direct at 24.

[13] For my proxy group, Mr. Parcell reported average, median, and high DCF values of 8.8%, 8.8%, and 9.6%, respectively.

Q. DO YOU BELIEVE THAT MR. PARCELL'S APPLICATION OF THE DCF MODEL PRODUCES A REASONABLE ESTIMATE OF INVESTORS' EXPECTATIONS?

A. No. As I explained in my Direct Testimony, the short-term growth rates used to apply the DCF model may be colored by recent historical trends or lingering economic and industry uncertainties, as exemplified by declining payout ratios and Value Line's relatively pessimistic rankings for the entire utility sector. As a result, these DCF growth rates do not necessarily capture investors' long-term expectations for the industry, and the resulting cost of equity estimates will be downward-biased.

Consider Mr. Parcell's reliance on historical growth rates, for example. 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 the projected growth rates, such as those published by Value Line and IBES, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q. IS THIS DOWNWARD BIAS OF HISTORICAL GROWTH MEASURES EVIDENT IN MR. PARCELL'S DCF ANALYSIS?

A. Yes, it is. For example, consider the historical growth measures for the companies in Mr. Parcell's reference group displayed on his Schedule 8. As shown there, the

average 5-year historical growth rate for the seven companies in his comparable group was 0.8%, with many of the individual growth rates being negative or zero.[14] Combining a growth rate of 0.8% with Mr. Parcell's adjusted dividend yield for his group of 4.5% implies a DCF cost of equity of 5.3%. This implied cost of equity is equal to the average yield on 20-year Treasury bonds used as the risk-free rate in Mr. Parcell's CAPM analysis. Clearly, an investment in public utility common stocks is not risk free, and Mr. Parcell's historical growth measures provide no meaningful information regarding the expectations and requirements of investors.[15]

Q. IS THERE EVIDENCE THAT MR. PARCELL AGREES IN PRINCIPAL WITH THE NOTION THAT DCF GROWTH RATES AND COST OF EQUITY ESTIMATES MUST PASS FUNDAMENTAL TESTS OF REASONABLENESS?

A. Yes. Although not discussed explicitly in his testimony, Mr. Parcell apparently agrees with this premise. In arriving at his DCF results, Mr. Parcell eliminated the average historical growth rate for one firm in his reference group – Puget Energy – presumably because the value was negative, and therefore nonsensical. Unfortunately, Mr. Parcell did not apply this same test of economic reasonableness to the remainder of his DCF growth rates, many of which were also negative or too low to be considered indicative of investors' expectations. The result is a built in downward bias to Mr. Parcell's DCF conclusions.

Q. IS THERE ALSO A DOWNWARD BIAS INHERENT IN MR. PARCELL'S RETENTION, OR "B X R", GROWTH RATES?

A. Yes. Mr. Parcell based his calculation of the internal, "b x r" retention growth rate on data from Value Line, which reports end-of-period results. If the rate of return,

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[14] Similarly, Mr. Parcell determined an average historical growth rate on Schedule 8 for the companies in my proxy group of 1.5%. Again, many of the individual growth measures were negative.

[15] Although not discussed in his testimony, Mr. Parcell eliminated

or "r" component of the "b x r" growth rate is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year. This downward bias, which has been recognized by regulators,[16] is illustrated in the table below.

Consider a hypothetical firm that begins the year with a net book value of common equity of $100. During the year the firm earns $15 and pays out $5 in dividends, with the ending net book value being $110. Using the year-end book value of $110 to calculate the rate of return produces an "r" of 13.6%. As the Federal Energy Regulatory Commission ("FERC") recognized, however, this year-end return "must be adjusted by the growth in common equity for the period to derive an average yearly return."[17] In the example below, this can be accomplished by using the average net book value over the year ($105) to compute the rate of return, which results in a value for "r" of 14.3%. Use of the average rate of return over the year is consistent with the theory of this approach to estimating investors' growth expectations, and as illustrated below, it can have a significant impact on the calculated retention growth rate:

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[16] See, *e.g.*, *Southern California Edison Company,* Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070.
[17] *Id.*

Beginning Net Book Value		$100
Earnings		15
Dividends		5
Retained Earnings		10
Ending Net Book Value		$110
"b x r" Growth	End-of Year	Average
Earnings	$ 15	$ 15
Book Value	$110	$105
"r"	13.6%	14.3%
"b"	66.7%	66.7%
"b x r" Growth	**9.1%**	**9.5%**

Because Mr. Parcell did not adjust to account for this reality in his analysis, the "b x r" retention growth rates that he considered are downward-biased and the results of his DCF cost of equity analysis are understated.

Q. WAS THE METHOD MR. PARCELL USED TO CALCULATE THE RATE OF RETURN, OR "R" VALUE OF HIS RETENTION GROWTH RATE CONSISTENT WITH HIS OTHER ANALYSES?

A. No. In applying the CAPM method, Mr. Parcell recognized that average book values should be used to compute the return on equity over the year. On Schedule 9, Mr. Parcell computed an annual return on book equity for the S&P 500 by dividing EPS by the average of the book values for the beginning and end of each year.

Q. WHAT OTHER OMISSION CAUSES MR. PARCELL'S RETENTION GROWTH RATES TO BE UNDERSTATED?

A. In his analysis of projected retention growth rates, Mr. Parcell ignored the impact of new stock issuances on the sustainable growth of the firm. As discussed in my Direct Testimony, 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. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically...[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[18]

In other words, the "sv" factor is an adjustment required by the DCF approach to ensure that the growth rate "g" is properly calculated for firms that plan to issue new common stock in the coming years. Mr. Hill also noted the importance of considering this source of growth when applying the DCF model using sustainable, or retention growth rates:

> Investor expectations regarding growth from external (sales of stock) must also be considered and examined.[19]

Because Mr. Parcell failed to consider the impact of expected new share issues in his analysis of projected retention growth, his DCF growth rates are again downward biased.

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[18] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31 –32.

[19] Hill Direct at 39.

Q. HAS THE ACC STAFF PREVIOUSLY RECOGNIZED THAT THE IMPACT OF GROWTH FROM NEW COMMON STOCK MUST BE CONSIDERED WHEN IMPLEMENTING THE DCF MODEL?

A. Yes. For example, in his January 16, 2006 testimony in a proceeding involving Arizona American Water Company, Staff witness Dennis Rogers noted that growth attributable to the sale of common stock is consistent with the theory underlying the DCF model and included the "sv" factor in developing his cost of equity estimates.[20]

Q. DOES MR. PARCELL'S DIVIDEND YIELD CALCULATION COMPORT WITH DCF THEORY?

A. No, not strictly. As noted in my Direct Testimony, under constant growth DCF theory, the dividend yield component (D_1) is computed as the expected dividend over the coming year, divided by the current stock price.[21] Meanwhile, Mr. Parcell used a spot dividend yield, increased by one-half of the expected growth rate (*i.e.*, $D_0(1+ \frac{1}{2}g)$). Because the constant growth form of the DCF model specifies that the correct dividend to use is the end-of-period value, not the mid-year value used by Mr. Parcell, his dividend yield and the resulting cost of equity estimates are understated. While the method used by Mr. Parcell to calculate the dividend yield is not novel, it does represent yet one other aspect of his DCF analysis that leads to downward-biased results.

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[20] Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405 (January 16, 2006) at 20-23.

[21] This was recognized by ACC staff witness Dennis Rogers in his January 16, 2006 testimony in Docket No. W-01303A-05-0405 at 15.

Q. IN LIGHT OF THIS CONSISTENT DOWNWARD BIAS AND THE PROBLEMS ASSOCIATED WITH DCF RESULTS GENERALLY, WHAT DO YOU BELIEVE WOULD BE A MORE REASONABLE APPROACH?

A. Aside from the fact that many of the growth measures typically used to apply the DCF model do not capture investors' long-term expectations, the specific problems associated with Mr. Parcell's historical and retention growth rates ensure that his conclusions are understated and fall short of investors' required return. To the extent that the ACC gives any weight to Mr. Parcell's DCF results, I would recommend consideration of only the very top of his DCF range, or 10.0%.

Q. HAS THE ACC STAFF RECOGNIZED THAT THERE ARE ALTERNATIVES TO THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. Yes. Recognizing that the constant growth assumptions are not likely to be representative of real-world circumstances for utilities, the ACC Staff has also implemented a multi-stage form of the DCF model.[22] Recall that the constant growth form is a simplified version of the general DCF model:

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

The general, or multi-state form of the DCF model can be used to estimate the cost of equity by substituting projections for a firm's future dividends (D_t) and price (P_t) for the variables in the equation, and imputing the cost of equity (K_e) by equating the future cash flows to the current price (P_0).

This approach was also recently applied by ACC Staff witness Dennis Rogers in his January 16, 2006 testimony in Docket No. W-01303A-05-0405 and adopted by

[22] See, *e.g.*, Direct Testimony of John S. Thorton, Docket No. W-03512A-03-0279 (October 15, 2003).

the ACC in its July 28, 2006 decision.[23] Based on projected dividends from Value Line and a terminal growth rate based on growth in Gross Domestic Product for the U.S. economy, Mr. Rogers applied the multi-stage DCF method as reflected on Schedule DRR-8 to his testimony.

Q. WHAT COST OF EQUITY IS PRODUCED FOR MR. PARCELL'S REFERENCE GROUP USING STAFF'S MULTI-STAGE DCF APPROACH?

A. Application of Staff's multi-stage DCF model to the firms in Mr. Parcell's group is presented on Attachment WEA-2RB. As shown there, this alternative to the constant growth form of the DCF model used by the ACC Staff results in an implied cost of equity for the firms in Mr. Parcell's reference group of 10.8%.

B. Risk Premium Approach

Q. PLEASE DESCRIBE MR. PARCELL'S APPLICATION OF THE CAPM.

A. Mr. Parcell applied the CAPM using a risk-free rate of 5.3%, based on the average yield on 20-year Treasury bonds for May-July 2006, a market risk premium of 5.8%, and the beta values published by Value Line. Mr. Parcell's market risk premium was based on historical data from two sources: 1) an examination of the earned rate of return on book equity for the S&P 500 versus 20-year Treasury bond yields for the period 1978-2004, and 2) the realized rates of return for common stocks and long-term government bonds published by Ibbotson Associates. Mr. Parcell concluded that his analysis of earned returns on equity for the S&P 500 implied an equity risk premium of 6.0%, and he calculated risk premiums of 6.5% and 4.9% based on the arithmetic and geometric mean returns from Ibbotson Associates, respectively.

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[23] Decision No. 68858, *Arizona American Water Company*, Docket No. W-01303A-05-0405 (July 28, 2006).

Q. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH MR. PARCELL'S APPROACH TO APPLYING THE CAPM?

A. 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 data that reflects the expectations of actual investors in the market. However, while Mr. Parcell noted that "the cost of capital is an economic and financial concept that refers to an ex-ante (before the fact) expected or required return,"[24] his application of the CAPM method was entirely premised on *historical* – not projected – rates of return. The primacy of current expectations was recognized by Ibbotson Associates:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[25]

By failing to look directly at the returns investors are currently requiring in the capital markets, as I did on Attachment WEA-6 to my Direct Testimony, Mr. Parcell's CAPM estimate significantly understates investors' required rate of return.

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[24] Parcell Direct at 5.

[25] Ibbotson Associates, *Stocks, Bonds, Bills and Inflation, 2005 Yearbook, Valuation Edition* at 23.

Q. HAS THE ACC STAFF ALSO RECOGNIZED THE IMPORTANCE OF CONSIDERING CURRENT EXPECTATIONS WHEN ESTIMATING THE MARKET RISK PREMIUM?

A. Yes. In his January 2006 testimony, Staff witness Dennis Rogers developed an expected market risk premium for the market as a whole using essentially the same method that I presented on Attachment WEA-6 to my Direct Testimony. Staff first derived a DCF cost of equity estimate for the market as a whole by combining the projected dividend yields and growth rates for all dividend-paying stocks followed by Value Line. Based on this approach, Staff witness Rogers calculated an expected market risk premium of 7.57%.

Q. WHAT DOES STAFF'S FORWARD-LOOKING CAPM APPROACH IMPLY WITH RESPECT TO THE COST OF EQUITY FOR MR. PARCELL'S REFERENC GROUP?

A. As shown on Attachment WEA-3RB, the ACC Staff's forward-looking CAPM approach results in an average cost of equity for Mr. Parcell's reference group of 12.2%, or 12.8% for the firms in my proxy group. This same approach was adopted by the ACC in its July 28, 2006 decision in *Arizona American Water*.[26]

Q. WAS MR. PARCELL JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A. No. Both the arithmetic and geometric means are legitimate measures of average return; they just provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The

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[26] Decision No. 68858, *Arizona American Water Company*, Docket No. W-01303A-05-0405 (July 28, 2006).

arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. Under the realized rate of return approach, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *Regulatory Finance: Utilities' Cost of Capital* had this to say:

> One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* When using historical risk premiums as a surrogate for the expected market risk premium, the relevant measure of the historical risk premium is the arithmetic average of annual risk premiums over a long period of time.[27]

Similarly, Ibbotson Associates concluded that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. ... The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[28]

One does not have to get deep into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The ACC is not setting a constant return

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[27] Morin, Roger A., *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Reports (1994) at 275, (emphasis added).

[28] Ibbotson Associates, *Stocks, Bonds, Bills and Inflation, 2006 Yearbook, Valuation Edition* at 77.

that APS is guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, APS' yearly return will be volatile, depending on a variety of economic and industry factors, and investors do not expect to earn the same return each year.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO THE CONCLUSIONS OF MR. PARCELL'S CAPM ANALYSIS?

A. For a variable series, such as stock returns, the geometric average will always be less than the arithmetic average. Accordingly, Mr. Parcell's reference to geometric average rates of return provides yet another element of systemic downward bias.

Q. DO THE RISK PREMIUMS MR. PARCELL DERIVES FROM IBBOTSON ASSOCIATES' DATA COMPORT WITH THOSE REPORTED BY THIS ORGANIZATION?

A. No. As I noted in my Direct Testimony, Ibbotson Associates computes the equity risk premium by subtracting the arithmetic mean income return (not the total return) on long-term Treasury bonds from the arithmetic average return on common stocks. As Ibbotson Associates explained:

> Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.[29]

In other words, Ibbotson Associates concluded that using only the income component of the long-term government bond return provides a more reliable estimate of the expected risk premium because investors do not anticipate capital losses for a risk-free security. Mr. Parcell, however, calculated his equity risk premiums using the

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[29] *Id.*

total return for Ibbotson Associates' long-term government bond series. As a result, his equity risk premiums fall far below what Ibbotson Associates reports and Mr. Parcell's CAPM cost of equity estimates are understated.

Q. IS YOUR ASSESSMENT OF THE CORRECT HISTORICAL RISK PREMIUM CONSISTENT WITH THE VIEWS OF THE ACC STAFF?

A. Yes. For example, in applying the CAPM to estimate the cost of equity, Staff witness Dennis Rogers used a 7.2% market risk premium based the difference between arithmetic mean returns for common stocks and government bond income returns. As Mr. Rogers stated:

> Ibbotson Associates calculated the historical risk premium by averaging the historical arithmetic differences between the S&P 500 and the intermediate-term government bond income returns. Staff's historical market risk premium estimate is 7.2 percent as shown in Schedule DRR-2.[30]

This is the exact same 7.2% historical market risk premium that I relied on in Attachment WEA-7 to my Direct Testimony.

Q. WHAT COST OF EQUITY IS PRODUCED BY THE HISTORICAL CAPM ANALYSIS ONCE THESE DEFICIENCIES ARE ADDRESSED?

A. Ibbotson Associates reports an arithmetic mean risk premium for the S&P 500 over the 1926-2005 time period of 7.1%.[31] As shown on Attachment WEA-4RB, when combined with Mr. Parcell's 5.3% risk free rate and the most recent beta values from Value Line, this results in CAPM cost of equity estimates of 11.8% for Mr. Parcell's reference group and 12.1% for the firms included in my proxy group.

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[30] Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405 (January 16, 2006) at 30.

[31] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at Appendix C, Table C-1, p. 262.

Again, this exact approach was recently accepted by the ACC in a July 28, 2006 decision.[32]

Q. IS MR. PARCELL'S APPLICATION OF THE COMPARABLE EARNINGS APPROACH INTERNALLY CONSISTENT?

A. No. On the one hand, Mr. Parcell concludes that his comparable earnings analysis indicates that investors anticipate a return of approximately 13.5% from the firms in the S&P 500.[33] On the other hand, Mr. Parcell asserts that this approach implies that "the cost of equity for APS is no greater than 10%."[34] These findings simply are not compatible. Within the context of the CAPM model applied by Mr. Parcell, if investors expect a forward-looking return on the S&P 500 of 13.5%, and accepting his risk free rate of 5.3%, this implies an equity risk premium for the market as a whole of 8.2%. Multiplying this 8.2% risk premium by the average Value Line beta reported by Mr. Parcell for his reference group of 0.89 implies an equity risk premium for an electric utility of 7.3%. In turn, adding this 7.3% risk premium to Mr. Parcell's risk free rate of 5.3% implies a cost of equity for his electric utility group of 12.6%.

Similarly, while Mr. Parcell implies that an earned return of 10% or less is reasonable, Value Line reports that electric utilities as a whole are anticipated to earn a return of 11.5% from 2007 through 2011.[35] The comparable earnings standard recognizes that APS must compete for capital against firms in its own industry. A return that is significantly below the 11.5% that Value Line expects for

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[32] Decision No. 68858, *Arizona American Water Company*, Docket No. W-01303A-05-0405 (July 28, 2006).

[33] Computed as the average of the 14.7% and 12.3% returns reported by Mr. Parcell for the 1992-2001 and 2000-2004 time periods, respectively.

[34] Parcell Direct at 31.

[35] The Value Line Investment Survey (Sep. 1, 2006).

electric utilities generally would undermine confidence in the financial integrity of the firm and its ability to attract capital.

Q. BASED ON THE METHODOLOGIES RECENTLY ADOPTED BY THE ACC STAFF AND APPROVED BY THE COMMISSION, WHAT COST OF EQUITY IS IMPLIED FOR MR. PARCELL'S REFERENCE GROUP?

A. As noted earlier, given the downward bias in Mr. Parcell's constant growth DCF results, the indicated cost of equity should be set at the very top of his range, or 10.0%. Meanwhile, application of the ACC Staff's multi-stage DCF model results in a cost of equity for Mr. Parcell's utility group of 10.8%. Taken together, these results imply an average DCF cost of equity of approximately 10.4%.

With respect to the CAPM, application of the ACC Staff's forward-looking risk premium approach produced an average cost of equity for Mr. Parcell's proxy group of 12.2%. Correcting the deficiencies in Mr. Parcell's historical CAPM analysis implied an indicated cost of equity of 11.8%. Combining these two values, consistent with the Staff methodology recently approved by the ACC, results in a CAPM cost of equity estimate of 12.0%. As shown below, Staff's approved methods imply an average cost of equity estimate for Mr. Parcell's reference group of 11.20%:

Method	Estimate
Average DCF Estimate	10.40%
Average CAPM Estimate	12.00%
Overall Average	**11.20%**

C. Other Factors

Q. DO YOU AGREE WITH MR. PARCELL (P. 37) THAT CONSIDERATION OF FLOTATION COSTS IS NOT WARRANTED IN THIS PROCEEDING?

A. No. Mr. Parcell's position is perplexing in light of his own research regarding the measurement and implementation of flotation cost adjustments.[36] In his 1993 paper, Mr. Parcell confirmed that "issuance costs have averaged 2 to 5 percent of the gross proceeds on new public stock sales," and noted that there are "a variety of mechanisms for the recovery of flotation costs."[37] While Mr. Parcell recognized that the issue of how best to account for issuance costs was not without controversy, he also documented the use of flotation cost adjustments by utility regulators.[38]

As discussed in detail in my Direct Testimony, apart from the impact of new equity issuances, a flotation cost adjustment to compensate for past equity issues is required to keep shareholders whole. The need to consider past flotation costs has been recognized in the financial literature, including sources that Mr. Parcell relied on in his testimony. Specifically, Ibbotson Associates concluded that:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[39]

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[36] Parcell, D. C., "The Flotation Cost Adjustment To Utility Cost of Common Equity, Theory, Measurement, and Implementation" *National Society of Rate of Return Analysts*, Twenty-Fifth Financial Forum (Apr. 28, 1993).

[37] *Id.*

[38] *Id.*

[39] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at 35.

As I demonstrated by way of example in my Direct Testimony (pp. 59-61), unless an adjustment to account for the costs of past equity issuances is included, investors will be denied the opportunity to earn their required return.

Meanwhile, Mr. Parcell's suggestion that there is no evidence of Pinnacle West incurring any flotation costs is incorrect. Clearly, any time a company issues new common equity, there are costs associated with underwriting and floating the stock issue to the public. Consider the $250 million equity issuance made by Pinnacle West in 2005, for example, the proceeds of which all went to APS. This single stock sale resulted in underwriting fees and other flotation costs totaling over $8.5 million. Unless an adjustment to the ROE is made to recognize these costs and those associated with all other prior sales of common stock, investors will be denied the chance to earn their required return.

Q. WHAT ABOUT MR. PARCELL'S CONTENTION (P. 37) THAT A FLOTATION COST ALLOWANCE IS UNNECESSARY BECAUSE THE MARKET-TO-BOOK RATIO FOR ELECTRIC UTILITIES IS GREATER THAN 1.0?

A. Whether or not the market-to-book ratio is greater than, or less than, 1.0 says nothing about the need to recognize the impact of legitimate costs of issuing common stock when establishing a fair rate of return. Investors determine the price they are willing to pay for a share of common stock based on their assessment of expected cash flows and relative risks. While I don't dispute Mr. Parcell's observation that sales of stock at a price that exceeds book value will cause the book value per share of existing shareholders to grow,[40] this doesn't change the fact that investors must be granted an opportunity to earn their required rate of return on

[40] Indeed, this growth related to sales of new common stock forms the basis for the "sv" adjustment that Mr. Parcell ignored in calculating the retention growth rates used in his DCF analysis.

all invested capital, including that portion paid out as issuance expenses. As I demonstrated in the example in my Direct Testimony, this can only occur if an upward adjustment to the ROE is made to account for flotation costs.

Q. WHAT IS YOUR CONCLUSION REGARDING MR. PARCELL'S RECOMMENDED ROE?

A. As documented in my Rebuttal Testimony, Mr. Parcell's ROE recommendation is downward-biased, with revisions to his analyses consistent with recent ACC Staff testimony and Commission decisions implying a fair rate of return on equity for APS on the order of 11.20%, before consideration of flotation costs. 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. A return well in excess of Mr. Parcell's recommendation is required if APS is to have the opportunity to maintain its credit standing and financial flexibility.

V. STEPHEN G. HILL

Q. WHAT OVERALL RATE OF RETURN DID MR. HILL PROPOSE FOR APS?

A. Mr. Hill proposed an overall rate of return for APS of 7.33%. Along with the component costs of debt and preferred stock, Mr. Hill combined a rate of return on equity of 9.25% with a capital structure composed of 50.0% common equity and a total debt ratio of 50.0%, including long- and short-term debt.

Q. BRIEFLY DESCRIBE HOW MR. HILL ARRIVED AT HIS RECOMMENDED COST OF EQUITY FOR APS.

A. Following a general description of economic and capital market conditions, Mr. Hill applied the constant growth DCF model to a group of thirteen other electric utilities. He then used three other methods – the CAPM, earnings-price ratio, and

market-to-book ratio – to check his DCF results. Based on these analyses, Mr. Hill concluded that the cost of equity for the firms in his comparable group is in the range of 9.25% to 9.75%. Based on the contention that his recommended capital structure implies less financial risk than his comparable group, Mr. Hill recommended an ROE at the very bottom of his range, or 9.25%, for APS. Mr. Hill argued against any upward adjustment to the return on equity for flotation costs, concluding that it was "unnecessary."

Q. WHAT IS YOUR OVERALL ASSESSMENT OF MR. HILL'S ROE RECOMMENDATION?

A. Mr. Hill is in a difficult position. By his own admission, "returns in the single-digit range seem to be low."[41] But rather than considering the implications of this assessment, he sets about finding a hodgepodge of carefully selected references to obscure this unavoidable conclusion. In fact, Mr. Hill's recommended ROE is far beyond the pale and falls well short of investors' required return. The reason that Mr. Hill was compelled to observe that his single-digit cost of equity recommendation seems to be low, is that *it is low*. So low, in fact, that it falls completely outside a reasonable range and is entirely inconsistent with mainstream benchmarks. This conclusion is only buttressed by the need to consider the consequences for APS' already weakened credit standing and the Company's continued need to keep pace with strong service area growth while financing deferred power cost balances. It is plainly evident that Mr. Hill's recommendations would be disastrous for APS and, ultimately, for customers as well.

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[41] Hill Direct at 7.

Q. DO THE RETURN ASSUMPTIONS UNDERLYING THE ACTUARIAL STUDIES OF PINNACLE WEST'S PENSION PLAN SUPPORT MR. HILL'S ROE RECOMMENDATION?

A. No. Incredibly, while Mr. Hill admits that his ROE recommendation appears low, he opines that investors' actual return expectations are even lower. The evidence Mr. Hill cites for his surprising finding is the return assumptions made in the administration of Pinnacle West's pension plan. Mr. Hill notes that Pinnacle West's 2005 Form 10-K Report indicated a 9.00% expected return on plan assets, which Mr. Hill stated were "comprised mostly of equity investments."[42] In fact, however, Pinnacle West reported on page 100 of this same report that the target asset allocation corresponding to this 9.00% return is comprised of only 60% equity securities. In fact, APS informed RUCO that the actual return it expects to earn on the equity component of its pension plan portfolio is approximately 11.0%.[43]

Q. CAN AN ASSUMED PENSION PLAN RETURN BE COMPARED DIRECTLY TO THE REQUIRED RETURN WE ARE TRYING TO ESTIMATE IN THIS CASE?

A. No. The return on pension plan assets is distinct from the ROE required by investors in the capital markets. This assumed return on plan assets was developed through simulations based on asset returns calculated over a 10-year time period, with the Towers Perrin document referenced by Mr. Hill specifically noting that their results "differ from those which would be calculated assuming independent annual returns."[44] Independent annual returns, which are analogous to arithmetic averages, are the appropriate benchmark for investors' expected rate of return.

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[42] *Id.* at 5.
[43] Response to RUCO 3-10.
[44] APS10620.

Q. IS THERE ANY OTHER EVIDENCE THAT MR. HILL'S REFERENCE TO APS' PENSION PLAN'S ASSUMED 9.0% RETURN IS MEANINGLESS?

A. Yes. Mr. Hill noted that his 9.0% return benchmark "is for common stocks generally, not for utility stocks, which would have a lower equity return expectation due to their lower risk."[45] Mr. Hill's market return of 9.0% can be converted to a return for electric utilities using his own application of the CAPM model. Assuming Mr. Hill's risk free rate of 5.16% and his proxy group beta of 0.83, a 9.0% return on the stock market as a whole would imply an ROE for his electric utility group of 8.3%.[46] This result falls almost 100 basis points below the bottom end of Mr. Hill's own ROE range and outside the realm of reasonableness indicated by any objective benchmark. Far from confirming the reasonableness of Mr. Hill's recommendation, this outcome only confirms the fundamentally illogical nature of his conclusions.

Q. ARE THE SELECTED ACADEMIC STUDIES REFERENCED BY MR. HILL REPRESENTATIVE OF INVESTORS'EXPECTATIONS?

A. No. Mr. Hill claims that "recent economic research" suggests that the market risk premium has fallen sharply, justifying his single-digit cost of equity recommendation for APS."[47] First, many of Mr. Hill's selected studies do not examine the forward-looking expectations of today's investors to estimate the required market rate of return in current capital markets. Instead of directly considering requirements in today's capital markets, as I did in my Direct Testimony on Attachment WEA-6, Mr. Hill is implicitly asserting that events and expectations for the time periods covered by these particular studies are more

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[45] Hill Direct at 8-13.

[46] 5.16% + 0.83(9.0% - 5.16%) = 8.3%.

[47] Hill Direct at 21.

representative of what is likely to occur going forward. This assertion runs counter to the assumptions underlying the use of the CAPM to estimate investors' required return, which as discussed earlier in response to Mr. Parcell, is a purely forward-looking model.

Moreover, even if historical studies were relevant in this context, there are other such studies of equity risk premiums published in academic journals that imply required rates of return considerably in excess of those selected by Mr. Hill. For example, a study reported in the *Financial Analysts' Journal* noted that the real risk premium for U.S. stocks averaged 6.9 percent over the period 1889 through 2000 and concluded that:

> Over the long term, the equity risk premium is likely to be similar to what is has been in the past and returns to investment in equity will continue to substantially dominate returns to investments in T-bills for investors with a long planning horizon.[48]

Combining this 6.9% real risk premium with a 3.0% inflation rate and Mr. Hill's 4.84% T-bill rate implies a current required rate of return on equity for the market as a whole of approximately 14.7% – far in excess of the single-digit returns cited by Mr. Hill.[49] Similarly, based on a study of *ex-ante* expected returns for a sample of S&P 500 firms over the 1983-1998 period, a 2003 article in *Financial Management* found an expected market risk premium of 7.2%,[50] identical to that used by the ACC Staff.

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[48] Mehra, Ranjnish, "The Equity Premium: Why Is It a Puzzle?", *Financial Analysts' Journal* (January/February 2003).

[49] Mr. Hill's T-Bill rate is reported at Appendix D, p. iv to his Direct Testimony.

[50] Harris, R.S., Marston, F. C., Mishra, D. R., and O'Brian, T. J., "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," *Financial Management* (Autumn 2003) at Table I.

Q. DO THE RESULTS OF THE EQUITY RISK PREMIUM STUDIES REPORTED BY MR. HILL MAKE ECONOMIC SENSE?

A. No. In fact, five of the studies cited as support for Mr. Hill's conclusions implied market equity risk premiums ranging from 1.8% to 4.0% and averaging approximately 3.3%.[51] But multiplying a market equity risk premium of 3.3% by Mr. Hill's beta of 0.83 for his reference group, and combining the resulting 2.7% risk premium with his 5.16% risk-free rate, results in an indicated cost of equity of approximately 7.9%. By any objective measure, such results fall woefully short of required returns from an investment in common equity. Mr. Hill's interpretation of recent academic research has little relation to the expectations of actual investors and no value as a benchmark in evaluating the reasonableness of his recommendations.

Q. DOES THE IBBOTSON & CHEN ARTICLE CITED BY MR. HILL (P. 13) PROVIDE ANY SUPPORT FOR HIS POSITION THAT THE MARKET EQUITY RISK PREMIUM HAS FALLEN PRECIPITOUSLY?

A. No. Mr. Hill's conclusion differs markedly from the evidence in the article by Roger G. Ibbotson and Peng Chen that he cited.[52] Based on the results of their study, Ibbotson and Chen concluded that:

> Our forecast of the equity risk premium is only slightly lower than the pure historical return estimate. We estimate the expected long-term equity risk premium ... to be about 6 percentage points arithmetically... (p. 88)

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[51] See, *e.g.*, Hill Direct at p. 8, ln. 11-12, p. 9, ln. 2, p. 11, ln. 17, p. 12, ln. 13, p. 12, ln. 20.

[52] Ibbotson, R., Chen P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

Apart from contradicting the findings of other studies selected by Mr. Hill, the 6.0% equity risk premium from Ibbotson and Chen disproves his contention that a single-digit cost of equity is reasonable.

Q. DOES MR. HILL OFFER A SIMPLE EXPLANATION AS TO WHY ALLOWED RETURNS ARE SO MUCH HIGHER THAN THE RESULTS OF HIS ANALYSES?

A. Yes. Mr. Hill asserts (p. 14) that regulatory commissions are ignorant as to this "new research" he cites in his testimony, and expresses his belief that allowed returns will decline as they develop an understanding of this information.

Q. BASED ON YOUR EXPERIENCE AS A REGULATORY STAFF MEMBER AND CONSULTANT, DOES THIS SEEM REASONABLE?

A. Far from it. The rate setting process is fractious and hard-fought, and the question of establishing a fair ROE is perhaps one of the most contentious issues among the various stakeholders. As a result, utilities, commission staff members, and intervenors typically devote considerable attention and resources in arguing their position before regulators. In my experience, authorized rates of return are decided based on careful consideration of extensive record evidence and staff members and commissioners have the resources and sophistication to assess the implications of current financial research and analyses. It is simply naïve of Mr. Hill to claim that authorized rates of return are somehow upward-biased because regulators have not been made aware of or understood the results of his selected crop of articles.

Q. DOES MR. HILL'S REFERENCE TO MARKET-TO-BOOK RATIOS FOR ELECTRIC UTILITIES DEMONSTRATE THE REASONABLENESS OF HIS 9.25% PERCENT RECOMMENDED COST OF EQUITY FOR APS?

A. No. In addition to other problems,[53] the argument that regulators should set a required rate of return to produce a market-to-book value of approximately 1.0 is fallacious. For example, *Regulatory Finance: Utilities Cost of Capital* noted that:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a M/B of 1.0, presumes that investors are masochistic. They commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is not a realistic or accurate view of regulation.[54]

Indeed, while Mr. Hill reports that investors' expect electric utilities to earn 10.35% percent on common equity, he suggests that regulators should allow them to earn 9.25%.[55] With market-to-book ratios above 1.0 times, Mr. Hill apparently believes that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall.

Within the paradigm of DCF theory, a drop in stock prices means negative growth, and if investors expect negative growth then this is the relevant "g" to substitute in the constant growth DCF model. In turn, a negative growth rate implies a DCF cost of equity for utilities less than their dividend yields. This, of course, is truly a nonsensical result, and a manifestation of Mr. Hill's confusion between DCF theory and practice.

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[53] Market-to-book ratios are impacted by other external factors unrelated to utility operations. For example, current or anticipated diversification into non-regulated activities may cause the market price of a utility's stock to deviate significantly from its book value.

[54] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utility Reports* (1994) at 256.

[55] Hill Direct at 21.

Q. HAVE REGULATORS PREVIOUSLY RECOGNIZED THE FALLACY OF RELYING ON MARKET-TO-BOOK RATIOS IN EVALUATING COST OF EQUITY ESTIMATES?

A. Yes. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[56]

The Initial Decision found that there was no support in Commission precedent for the use of market-to-book ratios to evaluate market derived cost of equity estimates and concluded that such arguments were to be treated as "academic rhetoric" unworthy of serious consideration.

Q. DOES THE FACT THAT BOND YIELDS ARE "LOW RELATIVE TO THE INTEREST RATE LEVELS THAT EXISTED IN THE MID-1980S"[57] IMPLY THAT MR. HILL'S RECOMMENDED 9.25% ROE IS REASONABLE?

A. No. While interest rates represent one logical reference point, the impact of fluctuating capital market conditions on the cost of equity is not readily determined. In fact, there is substantial evidence that equity risk premiums tend to move inversely with interest rates. In other words, when interest rates rise, equity risk premiums narrow, and when interest rates fall, equity risk premiums are greater. This inverse relationship has been recognized in the financial literature and by regulators.

Moreover, contrary to Mr. Hills assertion that "long-term capital costs have not increased to a substantial extent,"[58] as documented earlier, triple-B utility bond

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[56] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).

[57] Hill Direct at 16.

yields have increased approximately 80 basis points from the levels in my Direct Testimony. As I explained there, capital market participants generally anticipate that long-term interest rates will continue to rise. For example, the most recent forecast of GlobalInsight, a widely referenced forecasting service, calls for double-A public utility bond yields to average 6.92% over the next five years,[59] versus 6.13% in July 2006.[60] Meanwhile, the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy, anticipates that the double-A public utility bond yield will average of 7.18% for the period 2007-2011.[61]

Q. DOES THE SINGLE INVESTMENT ANALYST REPORT CITED BY MR. HILL SUPPORT HIS ALLEGATION THAT INVESTORS' RETURN EXPECTATIONS FOR UTILITIES ARE ESPECIALLY LOW?

A. No. On page 7 of his testimony, Mr. Hill resorts to a selected cite from A. G. Edwards in an attempt to support his position. But the 8.1% return figure cited in this report is simply another example of a mechanical application of the constant growth DCF model. It is not uncommon for stock research reports to include a perfunctory application of the DCF or CAPM models, but these results hardly represent an in-depth analysis of investors' expectations or their required rates of return. The fact that this 8.1% figure falls some 115 basis points below even Mr. Hill's anemic ROE recommendation amply demonstrates that this provides no insight as to a fair return on equity for APS. Indeed, A.G. Edwards noted that the median ROE authorized for the gas industry in 2005 was 10.6% and, in contrast to

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[58] *Id.* at 15.

[59] GlobalInsight, "The U.S. Economy: The 30-Year Focus" (First-Quarter 2006) at Table 34. This is the only series of projections for public utility bond yields reported by GlobalInsight.

[60] Moody's Investors Service, *Credit Perspectives* (Aug. 21, 2006) at 56.

[61] Energy Information Administration, "Annual Energy Outlook 2006" (Jan. 2006) at Table 19. This is the only series of projections for public utility bond yields reported by EIA.

APS, the report concluded that "gas utilities have typically been able to earn near or above their authorized return."[62]

A. DCF Analysis

Q. DID MR. HILL PROPERLY APPLY THE CONSTANT GROWTH DCF MODEL?

A. No. Mr. Hill began his DCF analysis by correctly stating:

> The DCF model relies on the equivalence of the market price of the stock (P) with the present value of the cash flows **investors expect from the stock**, providing the discount rate equals the cost of capital.[63]

Nevertheless, his application of the DCF model to his proxy group of utilities departed from this fundamental proposition because of his strict reliance on the mathematical DCF theory instead of the realities of investors' actual expectations in financial markets. The use of DCF models to estimate the cost of equity is essentially an attempt to replicate the market pricing mechanism that led to the observed stock price, with investors' required rate of return simply being inferred. In contrast, Mr. Hill applied the DCF model based on a strict interpretation of the academic theory underlying its derivation.

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[62] A.G. Edwards, "Gas Utilities Quarterly Review," April 6, 2006 at 6.

[63] Hill Direct at 34.

Q. WHAT IS WRONG WITH ADHERING STRICTLY TO THE THEORY UNDERLYING THE CONSTANT GROWTH DCF MODEL?

A. Enumerated in my Direct Testimony,[64] many unrealistic assumptions are required to derive the constant growth form of the DCF model, with Mr. Hill noting some of these infirmities in his testimony:

> The model also assumes that the company whose equity cost is to be measured exists in a steady state environment, i.e., the payout ratio and the expected return are constant and the earnings, dividends, book value and stock price all grow at the same rate, forever.[65]

Because the assumptions underlying the constant growth DCF model are never met in practice, the constant growth DCF model can, at best, only be considered an abstraction of reality. As such, the DCF model cannot universally produce correct measures of the cost of equity; rather, it can only serve as a potential guide to investors' required rate of return. Mr. Hill granted this limitation of the DCF model in his testimony:

> As with all mathematical models of real-world phenomena, the DCF theory does not exactly "track" reality.[66]

Therefore, the only inputs (i.e., cash flows) that matter in implementing the DCF model are those that investors used to value the utility's stock. Any application of the DCF model that does not focus exclusively on investors' actual expectations is a misuse of the DCF model to estimate the cost of equity.

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[64] Avera Direct at 31-32.
[65] Hill Direct at 34.
[66] *Id.*

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW MR. HILL DISREGARDS THIS PRINCIPLE?

A. Yes. Consider Mr. Hill's discussion of his hypothetical firm in Appendix B to his testimony. He stated that certain actual growth rates can be "unreliable" within DCF theory, and concluded that the proper growth rate to use with the DCF model is the theoretical "sustainable growth rate". But Mr. Hill's contention is wrong. The only correct growth rate to be used in the DCF model is the long-term growth rate investors actually incorporated into the observed stock price, irrespective of whether Mr. Hill considers it "ridiculous" or inconsistent with "the underlying fundamentals of growth in the DCF model."[67]

The fact is Mr. Hill confused the theory of the DCF model with its application. Professor Myron J. Gordon's complete mathematical DCF model is tautological. In other words, the constant growth DCF model is true by virtue of the strict assumptions made to derive it, and given these assumptions, any number of propositions can be "demonstrated" (*e.g.*, Appendix B, p. v). But to the extent that these assumptions are not met in practice and the DCF model does not "track reality", the theoretical DCF model will not conform to the real world. In turn, cost of equity estimates that are based solely on mathematical identities instead of investors' actual long-term growth expectations will not accurately measure their required rate of return. In a 2005 case decided by the New Hampshire Public Service Commission, regulators specifically concluded that Mr. Hill's DCF growth analysis "does not in our view reflect true market conditions."[68]

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[67] Hill Direct at Appendix B, p. iv.

[68] Order No. 24,473, *New Hampshire Public Utilities Commission* (June 8, 2005).

Q. ARE THERE OTHER PROBLEMS ASSOCIATED WITH THE GROWTH RATES UNDERLYING MR. HILL'S DCF RESULTS?

A. Yes. The sustainable, "br x sv" growth rates that formed the sole basis for Mr. Hill's DCF cost of equity estimates require an explicit assumption regarding the return on book equity ("r") that the utilities will earn in the future. But whereas Mr. Hill concludes that the DCF cost of equity for his reference group is 9.44%, the expected ROEs used by Mr. Hill to calculate his sustainable growth rates averaged 10.7% over the 2006-2011 period. In other words, Mr. Hill's analysis assumes that the companies in his group will earn a return significantly higher than the ROE he believes that regulators should adopt. For a regulated firm with earnings tied to the authorized return on book equity, this mismatch makes no sense.

Additionally, Mr. Hill's sustainable growth calculations fail to account for the fact that the returns on equity published by Value Line are based on end-of-period book equity rather than on average book equity. As discussed earlier in response to Mr. Parcell, this will understate actual returns because of growth in common equity over the year and results in a built-in downward bias in the resulting cost of equity estimates.

Q. DO THE RESULTS OF ALTERNATIVE METHODS SUPPORT MR. HILL'S DCF FINDINGS IN THIS CASE?

A. No. Even without incorporating expectations for higher interest rates, as noted in my Direct Testimony, application of the risk premium approach based on allowed rates of return for electric utilities resulted in a current cost of equity of 10.7%,[69] while applying the CAPM based on forward-looking expectations that are more

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[69] Avera Direct at 47.

consistent with the underlying theory of this approach produced an estimated cost of equity of 12.5%.[70]

Q. WHAT OTHER EVIDENCE INDICATES THAT MR. HILL'S DCF RESULT IS BIASED DOWNWARD?

A. As noted earlier, reference to allowed rates of return for other utilities also provides further confirmation that Mr. Hill's DCF result, and his ultimate ROE recommendation, fall significantly short of a reasonable rate of return. The rates of return on common equity authorized for electric and gas utilities averaged 10.57% and 10.60% for the first half of 2006, respectively.[71] This provides further confirmation that Mr. Hill's DCF results, which formed the basis of his recommendations, are far below the returns required by actual investors.

Q. IS MR. HILL ACCURATE TO SUGGEST (P. 51) THAT THE RESULTS OF THE CONSTANT GROWTH DCF MODEL ARE ONLY BEING QUESTIONED BY "UTILITY-SPONSORED" RATE OF RETURN WITNESSES?

A. No. 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, and regulators have customarily considered the results of alternative approaches in determining allowed returns. It has become increasingly evident to rate of return witnesses, regardless of whether they represent commission staffs, intervenors, or utilities, that conventional applications of the constant growth DCF model do not always provide accurate estimates of investors' required rates of return.

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[70] *Id.* at 51.

[71] Regulatory Research Associates, "Major Rate Case Decisions – January-June 2006," *Regulatory Focus* (July 6, 2006).

Accordingly, increased reliance is being placed on other methods to estimate the cost of equity, including alternative forms of the DCF model (e.g., multi-stage DCF models) and risk premium methods. The need to consider alternative methods is especially important where the results of one approach deviate significantly from cost of equity estimates produced by other applications, with risk premium methods suggesting a cost of equity far in excess of DCF values.

Q. HAS THE FALLIBILITY OF THE CONSTANT GROWTH DCF MODEL BEEN RECOGNIZED BY REGULATORS?

A. Yes. For example, the Public Utility Commission of Texas ("PUCT"), which I can assure you is not "utility-sponsored", made the following Findings of Fact in a case involving El Paso Electric Company:

> 109. Under present market and utility industry conditions, the constant discounted cash flow model does not provide reliable results.[72]

Mr. Hill refers to a dated article from Public Utility Reports (p. 52) in support of his claim that state regulators continue to rely on the DCF approach. But the DCF techniques that regulators are currently relying on may not be the constant growth methods advocated by Mr. Hill. In Florida, one of the states that Mr. Hill cites as continuing to rely on "standard" DCF techniques, the FPSC concluded in an April 29, 1998 decision that:

> Upon consideration, we find that the multi-stage DCF model employed by AT&T/MCI witness Cornell is superior to the single-stage DCF model used by BellSouth witness Billingsley for estimating the cost of capital of BellSouth. Witness Cornell testifies that the form of the DCF model he uses is well supported in the financial community. (p. 22)

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[72] Final Order, Docket No. 9945, *Public Utility Commission of Texas.*

State regulators in Pennsylvania, Iowa, and Alaska have also recognized the pitfalls associated with constant growth DCF results. The Pennsylvania Public Utility Commission concluded in a 1998 order that "the sole use of the DCF method can result in an understatement of the common equity cost rates."[73] Similarly, the Iowa Utilities Board concluded that "the DCF model may understate the return on equity in some circumstances,"[74] while regulators in Alaska specifically noted the importance of considering multiple approaches:

> We agree ... that investors are aware of all the various traditional cost of common equity models discussed in the financial literature. Absent good reason for believing that investors weight the results of one method more heavily than another in their assessment of an appropriate return, it is reasonable to hold that investors ascribe weight to them all.[75]

The Federal Communications Commission ("FCC") has also recognized the need for pragmatism when evaluating a fair return on equity, citing the need for an "accommodating and flexible position" that is not restricted to a single methodology.[76] More recently, in a 2003 decision establishing a fair rate of return for local service network elements, the FCC's Wireline Competition Bureau specifically considered and rejected the use of the DCF model, concluding that "the CAPM is the better mechanism for estimating the cost of equity in this proceeding."[77] With respect to the constant growth DCF approach advocated by

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[73] *United Water Pennsylvania,* Case No. R-00973947.

[74] *U.S. West Communications, Inc.*, 152 PUR 4th (June 17, 1994) at 459.

[75] *Trans Alaska Pipeline System*, Docket Nos. P-97-4 and P-97-7, Order Nos. 151 and 110 (Nov. 27, 2002) at 144-145.

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

[77] *Memorandum Opinion and Order*, CC Docket Nos. 00-218, 00-251, DA 03-2738 (Aug. 29, 2003) (*Virginia Arbitration Order*). at P. 71.

Mr. Hill, the Wireline Competition Bureau expressed serious doubts about this model's ability to accurately reflect investors' expectations in today's capital markets. Considering the deviation between Mr. Hill's results and other, objective benchmarks, considerable caution is warranted when evaluating the usefulness of DCF cost of equity estimates.

Q. YOU NOTED EARLIER THAT THE ACC STAFF HAS ALSO APPLIED A MULTI-STAGE FORM OF THE DCF MODEL. WHAT COST OF EQUITY IS INDICATED FOR MR. HILL'S UTILITY GROUP USING THIS APPROACH?

A. As shown on Attachment WEA-15RB the ACC staff's multi-stage DCF model that was adopted by the Commission results in an average cost of equity for Mr. Hill's reference group of 10.7%. This provides yet another indication that Mr. Hill's application of the DCF model produces illogical results.

Q. DO YOU AGREE WITH MR. HILL'S ASSERTIONS THAT CERTAIN COMPANIES SHOULD BE EXCLUDED FROM YOUR PROXY GROUP?

A. No. While Mr. Hill argued that certain companies should be dropped based on subjective arguments concerning the impact of non-regulated operations, he failed to demonstrate any link between his subjective musings and the investment risks perceived by investors. Moreover, there are significant errors and inconsistencies associated with his approach that justify rejecting Mr. Hill's proxy group altogether.

As discussed in my Direct Testimony (p. 33), a comparison of bond ratings indicates that investment risks for the firms in my proxy group of western utilities are relatively homogeneous. There are important factors distinguishing western utilities from those located in other regions and the Supreme Court has recognized

the relevance of geographical location.[78] My Direct Testimony demonstrated that investors are likely to regard my proxy group as facing similar market conditions and having comparable risks and prospects.

Q. DID MR. HILL DEMONSTRATE A NEXUS BETWEEN THE SUBJECTIVE CRITERIA HE USED TO DEFINE HIS PROXY GROUP AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A. No. Mr. Hill claimed that utilities with less than 70% of operating revenues from regulated electric operations or companies that had divested generation assets should be eliminated when determining a proxy group. But under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream or ownership of generating assets. As Mr. Hill correctly recognized:

> The Supreme Court of the United States has established, as a guide to assessing an appropriate level of profitability for regulated operations, that investors in [utilities] are to be given an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in the unregulated sector for assuming the same degree of risk.[79]

Mr. Hill presented no evidence that there is a connection between the subjective criteria that he employed and the views of actual investors in the capital markets.

Q. WHAT OBJECTIVE EVIDENCE CONFIRMS THE CONCLUSION THAT MR. HILL'S SUBJECTIVE CRITERIA ARE NOT SYNONYMOUS WITH COMPARABLE RISK IN THE MINDS OF INVESTORS?

A. Bond ratings are perhaps the most objective guide to utilities' overall investment risks and they are widely cited in the investment community and referenced by

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[78] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

[79] Hill Direct at 8 (emphasis added).

investors. While the bond rating agencies are primarily focused on the risk of default associated with the firm's debt securities, bond ratings and the risks of common stock are closely related. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Concrete evidence supporting the relationship between bond ratings and the quality of a security is abundant. ... The strong association between bond ratings and equity risk premiums is well documented in a study by Brigham and Shome (1982).[80]

Indeed, Mr. Hill also relied on bond ratings as one criteria in developing his comparable group.

As Mr. Hill noted, the companies he selected had a bond rating "between "A-" to 'BBB-"."[81] Meanwhile, a review of Mr. Hill's Schedule 3, which presents the basis of his sample group selection, indicates that, of the 19 firms excluded by Mr. Hill based on his electric revenue and generating asset tests, 10 had bond ratings within his permissible range. Of the remaining nine, all had bond ratings *above* Mr. Hill's required range, indicating *less* – not more – investment risk. Considering that credit ratings provide the most widely referenced benchmark for investment risks, a comparison of this objective risk indicator demonstrates that the risks of the companies eliminated under the subjective criteria proposed by Mr. Hill are either identical to, or less risky, than the companies included in his sample group.

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[80] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utility Reports* (1994) at 81.
[81] Hill Direct at 36.

Q. WHAT DO YOU CONCLUDE FROM THIS REVIEW OF CREDIT RATINGS?

A. Contrary to the allegations of Mr. Hill, comparisons of objective, published indicators that incorporate consideration of a broad spectrum of risks confirm that there is no link between the subjective tests he applied to define his proxy groups and the risk perceptions of investors.

Q. APART FROM BOND RATINGS, WHAT OTHER EVIDENCE INDICATES THAT MR. HILL'S CONCLUSIONS ARE BASELESS?

A. While Mr. Hill asserts that my proxy group is tainted by "additional unregulated company risk,"[82] this conclusion is contradicted by the very same risk benchmarks referenced in his testimony. As discussed subsequently, Mr. Hill cited S&P's *business profile* rank as an indicator of relative business risk. The average *business profile* rank for the firms in my proxy group is "6", which is identical to the rank for APS reported by Mr. Hill (p. 28). Again, this objective indicator cited by Mr. Hill confirms my conclusion that the risks of the companies in my proxy group are comparable to those of APS.

Q. WHAT ERRORS AND INCONSISTENCIES ARE ASSOCIATED WITH THE PROXY GROUP PROPOSED BY MR. HILL?

A. First, Mr. Hill screened all electric and combination electric and gas utilities followed by Value Line, with five of his reference utilities being engaged in both electric and gas utility operations.[83] Nevertheless, Mr. Hill based his revenue test solely on <u>electric</u> revenues and ignored the impact of other regulated activities, such as gas utility operations. Considering that Mr. Hill presented no explanation or evidence to suggest that the risks and required returns for other rate regulated

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[82] *Id.* at 54.

[83] *Id.* at Schedule 3.

operations are significantly different than for electric utilities, his failure to include the impact of other utility operations in implementing his revenue test is misleading.

For example, consider Avista Corporation ("Avista"), which Mr. Hill excluded from his reference group based solely on his revenue test.[84] Avista reported in its 2005 Form-10K report (Note 29) that it has three operating segments, with its Avista Utilities segment making up "total regulated utility operations."[85] Avista reported that operating revenues from its regulated utility segment totaled approximately $1.16 billion, or 83% of total operating revenues of $1.40 billion. Similarly, Puget Energy, Inc. informed investors that it "operates in one business segment referred to as the regulated utility segment," with revenues from utility operations making up virtually 100% of total revenues in 2005.[86]

Q. ARE THERE OTHER PROBLEMS ASSOCIATED WITH THE CRITERIA PROPOSED BY MR. HILL?

A. Yes. Due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as total revenues, between utility and non-utility sources. Consider the example of Dominion Resources, Inc. ("Dominion"), which Mr. Hill excluded from his sample group based on his contention that only 30% of Dominion's revenues were from electric utility sources. However, this 30% figure used to apply Mr. Hill's electric revenue criteria is unrelated to the actual percentage of regulated revenues for Dominion, which classifies its operations into four primary segments – Dominion

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[84] See Hill Direct at Schedule 3.

[85] Avista Corporation, Form 10-K Report (2005) at 110.

[86] Puget Energy, Inc., Form 10-K Report (2005) at Note 22.

Delivery, Dominion Energy, Dominion Generation and Dominion Exploration & Production.

Dominion Delivery includes regulated electric and gas distribution and customer service business, as well as nonregulated retail energy marketing operations. Similarly, Dominion Energy includes tariff-based electric transmission, natural gas pipeline, and natural gas storage businesses subject to varying degrees of rate regulation. Meanwhile, Dominion Generation includes the generation operations for both the electric utility and merchant power generation operations. As a result, even ignoring the fact that there is no clear link between the source of a utility's revenues and investors' risk perceptions, it is not possible to accurately apply Mr. Hill's criteria.

Q. WHAT OTHER INCONSISTENCIES ARE REFLECTED IN MR. HILL'S REFERENCE GROUP?

A. While Mr. Hill purports to include only those utilities with credit ratings between "A-"and "BBB-", three of the companies included in his reference group are actually rated below investment grade. As noted earlier, S&P downgraded its corporate credit rating for Central Vermont from "BBB-" to "BB+" in June 2005.[87] Similarly, in a recent review of utility credit ratings, S&P noted that DPL, Inc., another of Mr. Hill's proxy firms, is currently rated below investment grade at "BB+".[88] Finally, Unisource Energy, Inc. ("Unisource") reported that Moody's Investors Service ("Moody's) has assigned it a rating of "Ba2".[89] While S&P does not publish ratings for Unisource, it has assigned a corporate credit rating of "BB"

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[87] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (June 14, 2005).

[88] Standard & Poor's Corporation, "Issuer Ranking: U.S. Utility And Power Companies, Strongest to Weakest," *RatingsDirect* (Aug. 4, 2006).

[89] http://ir.uns.com/ratings.cfm (retrieved Sep. 7, 2006).

to Unisource's principal subsidiary, Tucson Electric Power.[90] Given the financial and operating challenges that typically lead to below-investment grade, or "junk" bond ratings, such firms hardly exemplify the "steady-state" required by Mr. Hill's theoretical DCF application.

Finally, while Mr. Hill indicated on his Schedule 3 that he excluded companies involved in a pending merger, Green Mountain Power Corporation announced on June 22, 2006 that it has entered into an agreement to be acquired by Northern New England Energy Corporation.[91] Accordingly, apart from the problems inherent in Mr. Hill's revenue test, there are other inconsistencies in Mr. Hill's application of his proxy group criteria.

B. Risk Premium Approach

Q. IS MR. HILL'S APPLICATION OF THE CAPM CONSISTENT WITH THE ASSUMPTIONS UNDERLYING THIS METHOD?

A. No. As explained in response to Mr. Parcell earlier, the CAPM is a forward-looking model that must be applied using data that reflects the expectations of actual investors in the market. However, while Mr. Hill noted that "[c]ost of capital analysis is a decidedly forward-looking, or *ex-ante*, concept,"[92] like Mr. Parcell, his application of the CAPM method was entirely premised on *historical* – not projected – rates of return. As I noted earlier and wish to re-emphasize, by failing to look directly at the returns investors are currently requiring in the capital

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[90] *Id.*

[91] "Green Mountain Power Corporation to be Acquired by Northern New England Energy Corporation, a subsidiary of Gas Metro Limited Partnership," *News Release* (June 22, 2006).

[92] Hill Direct at Appendix D, p. ii.

markets, as I did on Attachment WEA-6 to my Direct Testimony, Mr. Hill's CAPM estimate significantly understates investors' required rate of return.

Q. WAS MR. HILL JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE CAPM?

A. No. As discussed earlier in response to Mr. Parcell, under the realized rate of return approach, the arithmetic mean risk premium provides the best estimate of what investors might expect in future periods. Because the geometric average is lower than the arithmetic average, his reference to geometric average rates of return ensures that his cost of equity estimates will be significantly understated. Professor Jeremy Siegel, who Mr. Hill cited at page 11 of his testimony, found a differential of 2.0% between the geometric and arithmetic mean,[93] which is also consistent with the findings of Ibbotson Associates.[94]

Q. DOES MR. HILL'S CAPM ANALYSIS ACCURATELY REFLECT THE RISK PREMIUM DATA REPORTED BY IBBOTSON ASSOCIATES?

A. No. Like Mr. Parcell, while Mr. Hill claims to premise his analysis on data from Ibbotson Associates, he chooses to ignore the market risk premium reported directly from this source. As noted earlier, Ibbotson Associates reports that the long-horizon equity risk premium based on realized returns between 1926 and 2005 is 7.1%, versus the 6.5% and 4.9% figures used by Mr. Hill.[95] Again, this 7.1% risk premium is consistent with the 7.2% market risk premium from Ibbotson Associates adopted by the ACC Staff and used on Attachment WEA-7 to my Direct Testimony, only updated for an additional year of information.

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[93] Siegel, Jeremy J., "Perspectives on the Equity Risk Premium," *Financial Analysts Journal*, Vol. 61, No. 6, (Nov./Dec. 2005) at 69.

[94] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, 2006 Yearbook*, at 31.

[95] Hill Direct at Schedule 8.

Q. DO MR. HILL'S APPLICATIONS OF THE CAPM PROVIDE A MEANINGFUL GUIDE TO INVESTORS' REQUIRED RATE OF RETURN FOR APS?

A. No. Mr. Hill's CAPM results are biased downward for a number of important reasons. As indicated above, his analysis ignored investors' current expectations and focused entirely on historical data. In addition, Mr. Hill's reliance on geometric mean returns is inconsistent with using the CAPM to estimate the cost of equity and produced understated results. Finally, although Mr. Hill referenced data from Ibbotson Associates, his CAPM analysis did not incorporate the market risk premium reported by this source.

Q. DO YOU AGREE WITH MR. HILL THAT IT IS NOT APPROPRIATE TO CONSIDER EXPECTED INCREASES IN CAPITAL COSTS WHEN ESTABLISHING THE ALLOWED ROE FOR APS?

A. No. While Mr. Hill grants that yields "are likely to move slightly higher," he argues that any expectation of higher rates should be ignored when estimating investors' required return "because current interest rates best represent investors' current expectations for the future."[96] But consideration of interest rate forecasts does not presume that financial markets are wrong; rather, it recognizes that investors' required returns can and do shift over time with changes in capital market conditions. In fact, it is this very realization, and the general expectation that long-term capital costs will move higher, that warrants consideration of widely referenced forecasts of future bond yields. Indeed, as I noted earlier, bond yields have increased significantly since the analyses contained in my Direct Testimony were prepared.

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[96] *Id.* at 18 and 59-60.

As discussed in greater detail subsequently, utilities such as APS must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments if they are to maintain their financial flexibility and ability to attract capital. Expected capital market conditions during the time when rates established in this proceeding will be in effect are certainly one very valid barometer in ensuring that this fundamental economic and regulatory test is met.

Q. HAS YOUR OPINION CONCERNING THE USEFULNESS OF RISK PREMIUM METHODS CHANGED OVER TIME, AS CLAIMED BY MR. HILL?

A. No. On pages 60-61 of his testimony, Mr. Hill quotes from an affidavit I filed before the Federal Communications Commission ("FCC").[97] Then, as now, my position is that there is no infallible quantitative method to estimate the cost of equity. All of the available tools, including DCF and risk premium methods, must be used carefully and with common sense.

Because of the unobservable nature of cost of equity and the complexities of capital markets, I have consistently taken the position that no one quantitative method of estimating the cost of equity should be accepted without testing the reasonableness of the results against other methods. Indeed, Mr. Hill's use of multiple methods suggests that he agrees with this fundamental principle, although, as discussed earlier, he failed to follow it to any significant degree.

In Docket No. 84-800, the FCC proposed to use a risk premium formula to adjust the prescribed rate of return. My testimony in that case was that no <u>single</u> risk premium application should be relied upon in isolation. It was not that risk

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[97] *In the Matter of Authorized Rates of Return for the Interstate Services of AT&T Communications and Exchange Telephone Carriers*, CC Docket No. 84-800.

premium methods are useless, as Mr. Hill insinuates by quoting me out of context, but that each method of estimating equity risk premium suffers from some infirmity that limits its suitability for the type of "automatic pilot" rate of return determination that was being considered by the FCC.

Q. IS THERE ANYTHING WRONG WITH THE EQUITY RISK PREMIUM IN YOUR FORWARD-LOOKING CAPM ANALYSIS (ATTACHMENT WEA-6)?

A. No. As explained in my Direct Testimony, I estimated the current equity risk premium by first applying the DCF model to estimate investors' current required rate of return for the firms in the S&P 500 and then subtracting the yield on government bonds. Mr. Hill (p. 65-66) contends that this CAPM analysis is flawed because of an alleged upward bias in the market risk premium. In fact, however, the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. For example, in "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts" [*Journal of Applied Finance*, Vol. 11 No. 1, 2001], Robert S. Harris and Felicia C. Marston employed the DCF model and earnings growth projections from IBES – just as I did in Attachment WEA-6 to my Direct Testimony. Moreover, as noted earlier, the approach I used in Attachment WEA-6 is directly analogous to that relied on by the ACC Staff and recently adopted by the Commission.[98]

Mr. Hill's complaints about my forward-looking CAPM approach seem to hinge on the fact that this method produces an equity risk premium for the S&P 500 that is considerably higher than the unrealistic benchmarks he cites. But as I explained earlier, the benchmarks cited by Mr. Hill fail even the most rudimentary tests of

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[98] Decision No. 68858, *Arizona American Water Company*, Docket No. W-01303A-05-0405 (July 28, 2006).

economic logic. Estimating investors' required rate of return by reference to current, forward-looking data, as I have done, is entirely consistent with the theory underlying the CAPM methodology, which 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 required rates of return, the CAPM is best-applied using data that reflects the expectations of actual investors in the market. Rather than look backwards to risk premiums based on historical data, as Mr. Hill advocates, my analysis appropriately focused on the expectations of actual investors in today's capital markets.

C. Other Methods

Q IS THERE ANY SUBSTANCE TO MR. HILL'S MODIFIED EARNINGS-PRICE RATIO ("MEPR") ANALYSIS?

A. None whatsoever. First, it is worth noting that, as far as I am aware, Mr. Hill is alone in referencing the earnings/price ratio approach and this method has rarely, if ever, been used to establish the cost of equity in regulatory proceedings. Second, while Mr. Hill's statement that the earnings-price ratio understates the cost of equity when the utility's market-to-book ratio is greater than one is generally correct,[99] this simply confirms that the earnings/price ratio provides no guidance as to investors' actual required return.

Moreover, there is absolutely no theoretical justification for Mr. Hill's <u>averaging</u> the earnings-price ratio with a rate of return on book equity, either current or expected, as he did in his Schedule 10. This combination of apples and oranges is meaningless and provides no guide as to the expectations of actual investors. Nor

[99] Hill Direct at Appendix D, p. ix.

is such an averaging justified today, notwithstanding that the FERC may have utilized the expected rate of return on book value over twenty years ago as a check of reasonableness in establishing an upper bound to investors' required rate of return. Given the fact that Mr. Hill's MEPR analysis is fatally flawed and provides no information regarding the cost of equity for APS, it should be completely rejected by the ACC.

Q. DOES MR. HILL'S MARKET-TO-BOOK RATIO ("MTB") ANALYSIS PROVIDE ANY NEW OR ADDITIONAL INFORMATION AS TO THE RATE OF RETURN REQUIRED BY INVESTORS FROM HIS PROXY GROUP OF UTILITIES?

A. Absolutely none. As Mr. Hill acknowledged:

> This method is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method.[100]

That Mr. Hill's MTB analysis is nothing more than a restatement of his previous DCF analysis is also evident from his exhibits. In particular, there is little difference between Mr. Hill's average cost of equity of 9.44% using his DCF method[101] and the 9.31% using his MTB method based on Value Line's projections.[102] This similarity is not because the results of two different methods are converging, but because the DCF and MTB methods are essentially the same, only packaged slightly differently. And just as Mr. Hill's DCF analysis is fundamentally flawed because it is tied to tautological DCF theory rather than investors' actual expectations, so too is his MTB analysis since it is derived from the very same theoretical model and uses virtually identical inputs.

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[100] *Id.* at Appendix D, p. x.
[101] *Id.* at Schedule 7.
[102] *Id.* at Schedule 11.

Q. PLEASE COMMENT ON THE TABLE DISPLAYED ON PAGE 42 OF MR. HILL'S TESTIMONY.

A. While at first blush this table might suggest that Mr. Hill performed four different analyses that all indicated a cost of equity for his sample group falling within a fairly narrow range, this is not the case. As discussed earlier, Mr. Hill's CAPM analyses are flawed because they include geometric mean risk premiums, do not reflect the most recent market risk premium reported by his own source, and ignore investors' current expectations. Moreover, Mr. Hill's DCF and MTB analyses are, for all intents and purposes, one and the same and his MEPR analysis is meaningless, since he averaged "apples and oranges" to arrive at the values shown.

Q. DID MR. HILL INCLUDE AN ADJUSTMENT TO RECOGNIZE COMMON STOCK FLOTATION COSTS IN HIS RECOMMENDED FAIR RATE OF RETURN ON EQUITY?

A. No. Mr. Hill asserted (pp. 47-49) that an adjustment for flotation costs was unnecessary because:

- Electric utility common stocks are selling above book value;
- Issuance expenses are not out-of-pocket expenses;
- Because the amount of underwriter's fees is disclosed, investors have already accounted for issuance costs in their expectations;
- His DCF growth rate included an upward adjustment to recognize expectations of stock sales above book value; and,
- "Research" has shown that an adjustment for issuance expenses is unnecessary.

Q. DO THESE FIVE ASSERTIONS JUSTIFY MR. HILL'S DECISION TO IGNORE FLOTATION COSTS IN DETERMINING HIS RECOMMENDED RATE OF RETURN FOR APS?

A. No. While Mr. Hill's first observation about market-to-book ratios may be factually correct, it says nothing about whether or not a flotation cost adjustment is

warranted for APS. The fact that market prices are above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. In fact, even if APS is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issues of common stock.

Mr. Hill's second argument that flotation costs "are not out-of-pocket expenses" is simply wrong. Indeed, Mr. Parcell's review of flotation cost adjustments specifically noted that [i]ssuance costs are the *out-of-pocket* costs directly associated with the public offering of new shares."[103] Mr. Hill apparently believes that if investors in past common stock issues had paid the full issuance price directly to APS and APS had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Mr. Hill's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

Next, Mr. Hill argues that flotation costs have somehow already been accounted for in the price investors are willing to pay for new common stock. *Regulatory Finance: Utilities' Cost of Capital* noted that this double-counting argument is fallacious, concluding that:

> The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on

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[103] Parcell, D. C., "The Flotation Cost Adjustment To Utility Cost of Common Equity, Theory, Measurement, and Implementation" *National Society of Rate of Return Analysts*, Twenty-Fifth Financial Forum (Apr. 28, 1993) at 3 (emphasis added).

> its reduced rate base in order to produce a return equity to that required by shareholders.[104]

With respect to his contention that his DCF growth rate included an upward adjustment to recognize future sales of common stock above book value, the growth investors might expect resulting from sales of new stock above book value is a completely different issue than past or future flotation costs paid to third parties. While this "sv" growth component is properly considered in establishing investors' expectations when applying the DCF model, it in no way compensates for the impact of stock issuance costs.

Finally, contrary to Mr. Hill's assertions, the necessity of an adjustment for past flotation costs has been recognized in the literature. For example, in an article entitled "Common Equity Flotation Costs and Rate Making" published in *Public Utilities Fortnightly* (May 2, 1985), E.F. Brigham, D.A. Aberwald, and L.C. Gapenski demonstrate that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings. Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the

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[104] Morin, Roger A., *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Reports (1994) at 174.

> initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[105]

Finally, as noted earlier in response to Mr. Parcell, Ibbotson Associates, a source referenced repeatedly by Mr. Hill, noted that a flotation adjustment is properly considered in establishing the ROE for regulated utilities.

D. Capital Structure

Q. WHAT WAS THE CRUX OF MR. HILL'S ARGUMENT FOR A LOWER COMMON EQUITY RATIO?

A. Mr. Hill's recommendation to rejected APS' requested capital structure was based primarily on his contention that 1) APS' requested capital structure is different than its historical capitalization, 2) differences in business risk justify a lower equity ratio for APS, and 3) APS' requested capitalization is not consistent with industry benchmarks.

Q. DO MR. HILL'S ARGUMENTS CONCERNING APS' HISTORICAL CAPITAL STRUCTURE HAVE ANY MERIT?

A. No. First, it is worth noting that APS' requested equity ratio is not inconsistent with the capitalization maintained by the Company in the past. As shown on Mr. Hill's Schedule 2, APS maintained an average equity ratio over the five quarters reflected in his table of 51.46%. More importantly, however, Mr. Hill's observations regarding APS' capital structure in 2003 and 2004 simply are irrelevant in this proceeding. Historical ratios do not provide a basis to determine a reasonable capitalization for APS going forward, especially considering what is

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[105] *Id.* at 175.

required to maintain the Company's financial integrity in the face of weakened credit ratings and the challenges of raising the capital necessary to support its enormous investment requirements.

Mr. Hill's observation (p. 24) that APS "maintained investment-grade bond ratings" in the past is cold comfort considering Moody's recent decision to downgrade APS and Pinnacle West, in part due to "deterioration in key financial metrics."[106] Moody's went on to conclude that, because of regulatory uncertainties, "Moody's would look for APS to have financial metrics that are somewhat stronger than comparably rated utility operating companies."[107] Similarly, S&P recently observed that a key financial ratio for APS fell below the benchmarks established for a triple-B rating in 2005 and noted that "[a] negative rating change or outlook could result if leverage and cash flow metrics come under additional pressure."[108]

Q. SHOULD MR. HILLS ASSERTIONS CONCERNING THE RELATIVE RISKS OF APS AND PINNACLE WEST BE CONSIDERED IN EVALUATING A REASONABLE CAPITAL STRUCTURE IN THIS PROCEEDING?

A. No. First, the issue at hand is the determination of a capitalization and ROE that will meet the regulatory requirements of allowing investors an opportunity to earn a fair return while preserving APS' financial integrity and ability to access the capital markets on reasonable terms. As supported in my Direct Testimony, the testimony of APS' witnesses, and the testimony of Mr. Parcell, the Company's

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[106] Moody's Investors Service, "Moody's Downgrades Pinnacle West (Issuer Rating to Baa3) and Arizona Public Service (Sr. Uns. To

[107] Moody's Investors Service, "Credit Opinion: Arizona Public Serivce Company," *Global Credit Research* (May 9, 2006).

[108] Standard & Poor's Corporation, "Bulletin: ACC Staff Recommendation Has No Immediate Effect On Arizona Public Service Co. Rtg," *RatingsDirect* (Aug. 22, 2006).

requested capitalization is reasonable and consistent with these objectives and with industry benchmarks and investors' expectations.

Aside from the fact that the relative business risk of Pinnacle West is nothing more than a "red herring," Mr. Hill has presented no evidence to support his assertion that "Pinnacle West has higher business risk than APS."[109] In fact, the key measure of business risk – S&P's *business profile* ranking – cited by Mr. Hill contradicts his conclusion. While Mr. Hill noted that "S&P currently assigns APS a business profile score of 6,"[110] he failed to report that S&P has also assigned Pinnacle West *the exact same* ranking.[111] In other words, according to Mr. Hill's own benchmark, the business risks of Pinnacle West and APS are identical. Similarly, S&P's credit ratings, which consider both relative and business risks, are identical for Pinnacle West and APS. Mr. Hill's comparison between APS and "the highest risk, energy trading companies" is nothing more than a straw man and his arguments concerning relative risk and cross-subsidization should be ignored in their entirety.

Q. DO THE INDUSTRY CAPITALIZATION RATIOS THAT MR. HILL DERIVED REPRESENT A MEANINGFUL BENCHMARK FOR APS IN THIS CASE?

A. No. While APS's capital structure consists solely of long-term debt and common equity, Mr. Hill argued (p. 31) that short-term debt should be considered when comparing the Company with other electric utilities. Mr. Hill is wrong.

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[109] Hill Direct at 28.

[110] *Id.*

[111] Standard & Poor's Corporation, "Issuer Ranking: U.S. Utility And Power Companies, Strongest To Weakest," *RatingsDirect* (Aug. 4, 2006).

Q. WHY IS IT WRONG TO CONSIDER SHORT-TERM DEBT IN ESTABLISHING A CAPITAL STRUCTURE FOR APS, AS MR. HILL ADVOCATES?

A. Aside from the fact that Mr. Hill documents the absence of short-term debt in the Company's capitalization,[112] the facilities that APS employs to provide electric utility service are long-lived assets. In order to match the nature of APS' investment in plant and equipment, the capital structure should consist of permanent capital – long-term debt and common equity. Short-term debt is generally not viewed as part of the permanent capital used to finance investment in plant and equipment and is properly excluded in calculating the overall rate of return. Indeed, short-term debt is typically used to meet seasonal working capital needs, and may also be used to finance capital improvements until a sufficient balance has accumulated to economically issue common stock or long-term debt.

Q. DOES THE SIMPLE FACT THAT A UTILITY MAY HAVE SHORT-TERM DEBT OUTSTANDING AT A POINT IN TIME MEAN THAT IT SHOULD BE INCLUDED WHEN EVALUATING THE CAPITAL STRUCTURE?

A. No. For most utilities, short-term debt balances fluctuate depending on seasonal or other operating or financial requirements and the amount outstanding can vary considerably over time. Moreover, financing policies and practices vary widely among utilities. While isolated utilities may rely fairly heavily on short-term debt as a source of financing, others have little or no short-term debt outstanding, consistent with APS' requested capital structure.

For example, consider Xcel Energy, which Mr. Hill claimed "has approximately $1.5 billion in short-term debt." In contrast, Xcel Energy reported in its June 30, 2006 Form 10-Q report that short-term debt balances totaled only $138 million, or

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[112] Hill Direct at Schedule 2, p. 1.

a decline of over 90% from Mr. Hill's benchmark. This evidences that short-term debt is not used as a permanent source of financing for electric utilities and should not be regarded as part of the capital structure for regulatory purposes.

Q. WHAT OTHER SPECIFIC PROBLEMS ARE ASSOCIATED WITH THE INDUSTRY BENCHMARKS MR. HILL USED TO EVALUATE APS' CAPITAL STRUCTURE?

A. The industry common equity ratios that Mr. Hill cites as benchmarks are distorted and inconsistent with the premise of the capitalization he derived for APS. For example, Hawaiian Electric Industries' ("HEI") June 30, 2006 Form 10-Q Report reflected the following capital structure balances:

Component	$ (Mil)	Percent
Short-term Borrowings	$ 296.5	11.5%
Long-term Debt	1,033.1	40.2%
Preferred Stock	34.3	1.4%
Common Equity	1,205.1	46.9%
Total	$2,569.0	100.0%

But in contrast to the 46.9% equity ratio reflected above, Mr. Hill reported an equity ratio of 37% for HEI.[113] The only possible explanation for the vastly lower equity ratio relied on by Mr. Hill is that it considered short-term deposit liabilities associated with HEI's unregulated banking subsidiaries. Of course, this directly contradicts Mr. Hill's position that the impact of non-regulated activities should not be considered when establishing the ROE for APS.

Meanwhile, the average capital structure ratios presented by Mr. Hill are also distorted because they include downward-biased equity ratios associated with

[113] *Id.* at Schedule 2, p. 4.

speculative grade companies. For example, consider the equity ratios in the table below:

Company	Equity Ratio
Allegheny Energy	31%
CMS Energy	22%
Sierra Pacific Resources	32%
TECO Energy	29%
Unisource Energy	32%

S&P has assigned a corporate credit rating of "B" to Sierra Pacific Resources, with the remaining companies being rated double-B. With respect to CMS Energy, for example, S&P observed that an impairment charge related to a cogeneration venture had caused the company to fail coverage tests specified by its first mortgage bonds and led to a drastic decline in common equity:

> The action reflects the charge's negative impact on the balance sheet, because it cuts common equity about 14% and considerably boosts leverage just as CMS needs to continue improving its overall financial profile to levels more commensurate with current ratings [114]

The financial ratios of utilities with "junk" ratings simply have no place in an evaluation of an appropriate capital structure and fair rate of return for APS. By including capital structure ratios for utilities under financial stress, Mr. Hill perpetuates the downward bias that characterizes his conclusions.

Q. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF APS'S REQUESTED EQUITY RATIO?

A. Considering APS' ongoing efforts to improve its financial standing, and the need to support the Company's financial flexibility, there is no justification for Mr. Hill's recommendation to depart from APS' proposed capital structure. The decision of

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[114] "S&P puts CMS Energy, Consumers Energy on CreditWatch, negative," *Platts Commodity News* (Nov. 1, 2005).

S&P and Fitch to downgrade Central Vermont from triple-B to below investment grade highlights the importance of maintaining sufficient common equity to preserve the utility's creditworthiness, even during times of stress. Despite a common equity ratio that exceeds 60%, S&P and Fitch determined that Central Vermont's financial position was inadequate to support an investment grade rating in the face of an unfavorable regulatory order.[115]

APS' proposed capital structure is just one reflection of the Company's ongoing efforts to enhance its credit standing and maintain access to capital on reasonable terms in order to ensure its ability to meet its obligations to customers. The reasonableness of the Company's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, APS' relative risks and circumstances, the need to support continued system investment, and the imperative of maintaining continuous access to capital, even during times of adverse industry and market conditions. As the experience of Central Vermont illustrates, even a healthy equity cushion may not be sufficient to support a utility's credit ratings when investors perceive a lack of regulatory support.

VI. ATTRITION ADJUSTMENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section discusses the necessity of an attrition adjustment to meet the end result standards of *Hope* and *Bluefield*. There is one area of complete agreement between Mr. Parcell, Mr. Hill, and me – the allowed return should meet the end result test of being sufficient to maintain APS' financial integrity, preserve the

[115] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (June 14, 2005); "Fitch Ratings Downgrades CVPS," *Business Wire* (June 20, 2005).

Company's ability to attract capital, and provide investors with sufficient compensation for risk. While we disagree on what level of return investors' require given current market conditions, we seem united on the proposition that APS should have an opportunity to earn that market-based return. The economic reality, based on past experience and future projections, is that APS will in all likelihood suffer attrition so that actual returns will fall systematically short of the allowed return built into the rate order. In other words, allowed return will not translate into an opportunity for investors to earn that same return.

The amalgamated effect of growth, massive capital investment needs, and unrecovered costs combines with regulatory lag to prevent APS from having a realistic opportunity to earn whatever return is ultimately allowed by this Commission. In their Rebuttal Testimony, Mr. Brandt and Mr. Wheeler discuss attrition from the perspective of the Company's experience and projections. In this section, I examine the causes of attrition, the regulatory mechanisms to deal with attrition, and an adjustment to the allowed return to mitigate the impact of attrition from the perspective of a financial analyst and former regulator. Unless attrition is addressed, fine-tuning the determination of the market required return is a largely futile exercise. Investors and rating agencies look past the "sticker price" of the allowed return to end result of what the utility can reasonably be expected to earn.

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. WHAT IS YOUR PERSONAL EXPERIENCE WITH ATTRITION?

A. I began studying regulatory finance and consulting with commissions in the early 1970's. Attrition was a recognized issue that could thwart a utility's ability to earn its allowed ROE, depending on the facts and circumstances of the particular utility. As fuel prices and inflation started to increase, attrition became a more pressing problem in many parts of the country. When I joined the staff of the Public Utility Commission of Texas ("PUCT") in 1977, the electric utilities operating in Texas were suffering from significant attrition that was threatening the ability of our jurisdictional companies to raise capital. There were a number of tools available to deal with attrition. The pass-through of all fuel and purchased power costs helped to attenuate attrition. Known and measurable changes to investment and costs could be factored into the historical test year so that there was less of a mismatch between expected cost and investment level and those used to set rates. We also processed rate cases as quickly as possible to reduce regulatory lag. To assure that the utilities had an opportunity to earn the return recommended by the PUCT staff, we would routinely project the utility's earnings after rates went into effect. If we found a deterioration in the return on equity and other financial indicators, the PUCT staff would recommend including construction work in progress ("CWIP") in rate base. If the inclusion of CWIP was insufficient to bring projected financial indicators to the levels necessary to maintain the utility's financial integrity, ability

to attract capital, while providing a return commensurate with risk, my staff would recommend an additional attrition allowance to insure that the *Hope* and *Bluefield* end result tests were met.

Throughout my career as a consultant and teacher, attrition has remained an issue that arises in particular circumstances of growth, rapidly expanding utility investment, rising costs, inflation, and regulatory lag. The problem has been less of an industry-wide problem as the levels of growth, new investment, and inflation for most utilities has moderated from that experience in the 1970's and 1980's. Yet attrition can still arise in particular circumstances, such as those faced now by APS. For example, in addressing the need to increase investment in the interstate transmission infrastructure, FERC has recognized that changes in ratemaking methods are necessary to attract capital to transmission companies and regional transmission organizations. Included in the policies adopted by FERC are methods designed to alleviate investors' concerns regarding the possible impact of attrition, such as pass-through of costs and provisions to include new investments in rates on a prospective basis.

Q WHY IS IT NECESSARY TO DEAL WITH 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 itself. To be fair to investors and to benefit customers, a regulated utility must have an <u>opportunity to actually earn</u> 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 embraced by Mr. Parcell, Mr. Hill, and me are met. Yet, Mr. Parcell and Mr. Hill examined a hypothetical end result in the theoretical world where the test year is repeated in the

future. Such a test is not relevant to the investors and rating agencies that will determine the ability of APS to attract the capital so necessary to assure continued reliable and economical electric service in Arizona.

Q. HAS THE INVESTMENT COMMUNITY RECOGNIZED THE RISKS ASSOCIATED WITH ATTRITION AND LAG IN ITS EVALUATION OF APS?

A. Yes. Earlier this year, S&P noted that the slow pace of regulatory adjustments in Arizona acts as a drag on utility finances, especially considering the pressures of high growth.[116] With respect to APS specifically, S&P reiterated that cash flows are "highly predicated on the outcome and timing of APS' pending rate case," and concluded that regulatory lag could result in depressed financial metrics and, ultimately, lower credit ratings.[117] Similarly, Moody's noted the weakness attributable to "below average assurance of timely recovery of costs and investments," observing that "APS' 2003 rate case was not concluded until April 2005," and "[a] fuel surcharge mechanism requested as part of the 2003 rate case was not implemented until February 2006."[118] Both rating agencies have clearly recognized the difficulties faced by APS in recovering necessary costs on a timely basis.

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

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[116] Standard & Poor's Corporation, "Credit Factors for U.S. Natural Gas Distributors," *RatingsDirect* (Feb. 28, 2006).

[117] Standard & Poor's Corporation, "Research Update: Arizona Public Service's $400 Million Bonds Rated BBB-," *RatingsDirect* (July 31, 2006).

[118] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Global Credit Research* (May 9, 2006).

and other forward-looking mechanisms is also useful in ameliorating the impact of attrition, as is 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 NOW?

A. The unique circumstances of APS have led to an attrition problem just as severe as I observed for electric utilities in the turbulent decades of the 1970's and 1980's. APS is experiencing significant growth in customers and has to finance a huge capital investment program. Regulatory lag is also prevalent in Arizona. While the Commission's past constructive actions have been helpful in preventing APS' credit ratings from falling below investment grade pending the outcome of this case, attrition remains a major concern of the investment community. Investors recognize 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:

> When examining the quality of regulation, Standard & Poor's factors in what level of support the utility might get in times of distress, when its needs are most acute.[119]

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[119] Standard & Poor's Corporation, "Regulation and Credit Quality in the U.S. Utility Sector," *RatingsDirect* (Jan. 30, 2003).

S&P went on to note the importance of financial flexibility, especially considering the capital markets' ability to constrict access to capital when investors' confidence is compromised.

Q. CAN AN ADJUSTMENT TO ALLOWED RETURN ON EQUITY BE USED TO OFFSET ATTRITION?

A. Yes. The allowed return can be set with a margin over the cost of capital so that when rates go into effect the utility has an opportunity to actually earn its cost of capital. That end result would maintain the utility's financial integrity, ability to attract capital and offer investors fair compensation for the risk they bear. Ibbotson Associates, a source used by Mr. Parcell, Mr. Hill, and me noted that adjustments to the allowed return may be appropriate, including the potential that "regulatory conditions may require that the allowed rate of return be different from the cost of capital."[120] In this case, adding an increment to the cost of equity is the most logical way to offset the effect of attrition and ensure that APS has the opportunity to actually earn the cost of equity capital. Schedule F1 (p. 116) of APS' January 31, 2006 filing projects a return on equity of 9.8% in 2007 <u>if the full rate request is granted.</u> As documented by Mr. Brandt, this calculation assumes that new rates become effective on January 1, 2007. I understand that the current schedule for this case may result in new rates that are not in effect until May 2007. But even under a scenario where new rates are effective at the beginning of 2007 and the Company's full rate full rate request is granted, the projected earned return will fall 170 basis points below the allowed return. Thus, 170 basis points is the minimum attrition adjustment to the cost of equity in order to achieve a fair rate of return that would meet the *Hope* and *Bluefield* standards. Moreover, Mr. Brandt

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[120] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, 2006 Yearbook, Valuation Edition* at 35.

calculates that the return on equity will fall further in 2008, confirming the absolute minimum attrition adjustment indicated by Schedule F1 of 170 basis points. Given the likely timing of rate relief and the dynamics faced by APS, there is every reason to believe that attrition would overcome the minimum adjustment and APS would still not earn its cost of capital. Further, as demonstrated by Mr. Brandt, if the Staff or RUCO's proposals are accepted, a much higher adjustment is required to meet financial integrity, capital attraction, and investor compensation standards.

The Supreme Court recently 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.[121] 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.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

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[121] *Verizon Communications, et al v. Federal Communications Commission, et al*, 535 U.S. 467 (2002). While I cannot comment of 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.

ALLOWED ROE

PARCELL & HILL GROUPS

	Allowed ROE
Parcell Proxy Group	
Cleco Corp.	12.25%
DTE Energy	11.00%
Energy East	10.77%
Hawaiian Electric	10.82%
Pinnacle West	--
PNM Resources	10.33%
Puget Energy	10.30%
Average	**10.91%**

Hill Proxy Group	
Central Vermont PS	10.00%
FirstEnergy Corp.	9.75%
Green Mountain Pwr	10.50%
Progress Energy	12.42%
Ameren Corp.	10.92%
Cleco Corp.	12.25%
DPL, Inc.	11.00%
Empire District	11.00%
Entergy Corp.	10.97%
Hawaiian Electric	10.82%
PNM Resources	10.33%
Pinnacle West	--
Unisource Energy	10.67%
Average	**10.89%**

Source: *AUS Monthly Utility Report* (June 2006). Provided in response to APS/STAFF/WEA 3.10.

MULTI-STAGE DCF MODEL

PARCELL REFERENCE GROUP

Company	(a) Recent Price	(a) 2006 Div.	(a) 2007 Div.	(a) 2009-11 Div.	(b) Annual Change	(c) Terminal Growth	Annual Cash Flows Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	End Yr 5	(d) Implied Cost of Equity
Cleco Corp.	$22.00	$ 0.90	$ 0.90	$ 1.00	$ 0.03	6.8%	$0.45	$0.90	$0.93	$0.97	$1.00	$29.10	10.5%
DTE Energy	$39.93	$ 2.06	$ 2.06	$ 2.10	$ 0.01	6.8%	$1.03	$2.06	$2.07	$2.09	$2.10	$52.18	11.1%
Energy East	$22.55	$ 1.18	$ 1.24	$ 1.40	$ 0.05	6.8%	$0.59	$1.24	$1.29	$1.35	$1.40	$29.73	11.8%
Hawaiian Electric	$28.10	$ 1.24	$ 1.24	$ 1.24	$ -	6.8%	$0.62	$1.24	$1.24	$1.24	$1.24	$36.83	10.4%
Pinnacle West Capit	$43.44	$ 2.03	$ 2.13	$ 2.43	$ 0.10	6.8%	$1.02	$2.13	$2.23	$2.33	$2.43	$57.45	11.3%
PNM Resources Gro	$27.13	$ 0.86	$ 0.92	$ 1.10	$ 0.06	6.8%	$0.43	$0.92	$0.98	$1.04	$1.10	$36.20	10.0%
Puget Energy, Inc.	$22.40	$ 1.00	$ 1.00	$ 1.10	$ 0.03	6.8%	$0.50	$1.00	$1.03	$1.07	$1.10	$29.55	10.8%
Average													10.8%

(a) The Value Line Investment Survey (June 2, June 30, & Aug. 11, 2006).
(b) Annual change in dividend between 2007 and 2009-11.
(c) Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405, at Schedule DRR-8.
(d) Discount rate that equates the present value of cash flows in years 1-5 with Recent Price.

	(a)	(b)	(c)	(d)
Parcell Reference Group	**Risk-free Rate**	**Beta**	**Risk Premium**	**Cost of Equity**
Cleco Corp.	5.3%	1.25	7.57%	14.8%
DTE Energy	5.3%	0.75	7.57%	11.0%
Energy East	5.3%	0.90	7.57%	12.1%
Hawaiian Electric	5.3%	0.70	7.57%	10.6%
Pinnacle West	5.3%	1.00	7.57%	12.9%
PNM Resources	5.3%	1.00	7.57%	12.9%
Puget Energy	5.3%	0.80	7.57%	11.4%
Average				**12.2%**
Avera Reference Group				
Black Hills Corp.	5.3%	1.10	7.57%	13.6%
Edison International	5.3%	1.10	7.57%	13.6%
Hawaiian Electric	5.3%	0.70	7.57%	10.6%
IDACORP, Inc.	5.3%	1.00	7.57%	12.9%
MDU Resources Grou	5.3%	1.00	7.57%	12.9%
PNM Resources Grou	5.3%	1.00	7.57%	12.9%
Pinnacle West Capital	5.3%	1.00	7.57%	12.9%
Puget Energy, Inc.	5.3%	0.80	7.57%	11.4%
Sempra Energy	5.3%	1.05	7.57%	13.2%
Xcel Energy	5.3%	0.90	7.57%	12.1%
Average				**12.8%**

(a) Parcell Direct at Schedule 10.
(b) The Value Line Investment Survey, *Summary & Index* (Aug. 25, 2006).
(c) Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405 at 31.
(d) (a) + (b) x (c).

MULTI-STAGE DCF MODEL

HILL REFERENCE GROUP

Company	(a) Recent Price	(a) 2006 Div.	(a) 2007 Div.	(a) 2009-11 Div.	(b) Annual Change	(c) Terminal Growth	Annual Cash Flows Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	End Yr 5	(d) Implied Cost of Equity
Central Vermont PS	$17.25	$ 0.92	$ 0.92	$ 0.92	$ -	6.8%	$0.46	$0.92	$0.92	$0.92	$0.92	$22.48	11.2%
FirstEnergy Corp.	$52.02	$ 1.82	$ 1.94	$ 2.30	$ 0.12	6.8%	$0.91	$1.94	$2.06	$2.18	$2.30	$69.31	10.3%
Green Mountain Pw	$28.93	$ 1.12	$ 1.24	$ 1.54	$ 0.10	6.8%	$0.56	$1.24	$1.34	$1.44	$1.54	$38.66	11.1%
Progress Energy	$40.96	$ 2.44	$ 2.50	$ 2.62	$ 0.04	6.8%	$1.22	$2.50	$2.54	$2.58	$2.62	$53.41	12.0%
Ameren Corp.	$50.29	$ 2.54	$ 2.54	$ 2.54	$ -	6.8%	$1.27	$2.54	$2.54	$2.54	$2.54	$65.65	10.9%
Cleco Corp.	$22.00	$ 0.90	$ 0.90	$ 1.00	$ 0.03	6.8%	$0.45	$0.90	$0.93	$0.97	$1.00	$29.10	10.5%
DPL, Inc.	$26.46	$ 1.00	$ 1.04	$ 1.16	$ 0.04	6.8%	$0.50	$1.04	$1.08	$1.12	$1.16	$35.07	10.3%
Empire District	$20.40	$ 1.28	$ 1.28	$ 1.28	$ -	6.8%	$0.64	$1.28	$1.28	$1.28	$1.28	$26.43	12.0%
Entergy Corp.	$70.24	$ 2.16	$ 2.32	$ 2.80	$ 0.16	6.8%	$1.08	$2.32	$2.48	$2.64	$2.80	$93.82	10.0%
Hawaiian Electric	$28.10	$ 1.24	$ 1.24	$ 1.24	$ -	6.8%	$0.62	$1.24	$1.24	$1.24	$1.24	$36.83	10.4%
PNM Resources Gro	$27.13	$ 0.86	$ 0.92	$ 1.10	$ 0.06	6.8%	$0.43	$0.92	$0.98	$1.04	$1.10	$36.20	10.0%
Pinnacle West Capit	$43.44	$ 2.03	$ 2.13	$ 2.43	$ 0.10	6.8%	$1.02	$2.13	$2.23	$2.33	$2.43	$57.45	11.3%
Unisource Energy	$33.72	$ 0.84	$ 0.92	$ 1.16	$ 0.08	6.8%	$0.42	$0.92	$1.00	$1.08	$1.16	$45.21	9.5%
Average													**10.7%**

(a) The Value Line Investment Survey (June 2, June 30, & Aug. 11, 2006).
(b) Annual change in dividend between 2007 and 2009-11.
(c) Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405, at Schedule DRR-8.
(d) Discount rate that equates the present value of cash flows in years 1-5 with Recent Price.

EXHIBIT
APS-43
admitted

REJOINDER TESTIMONY OF WILLIAM E. AVERA

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

October 4, 2006

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REJOINDER TESTIMONY OF WILLIAM E. AVERA
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E01345A-05-0827)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is William E. Avera. My business address is 3907 Red River, Austin, Texas, 78751.

Q. ARE YOU THE SAME WILLIAM E. AVERA WHO PREVIOUSLY FILED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. My purpose here is to respond to the Surrebuttal Testimony of Mr. David C. Parcell and Mr. James R. Dittmer, on behalf of the Staff of the Arizona Corporation Commission ("ACC" or "the Commission"), and Mr. Stephen G. Hill, on behalf of the Residential Utility Consumer Office ("RUCO"), concerning a fair rate of return on equity ("ROE") for Arizona Public Service Company ("APS" or "the Company"). My Rejoinder Testimony does not respond to each and every argument presented by these witnesses concerning the more technical details underlying the analyses of an ROE for APS because this evidence is already contained in my Direct and Rebuttal testimonies. Rather, my Rejoinder testimony targets several key issues that must be considered to ensure that the allowed ROE for APS meets the economic tests required by established regulatory principles.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY?

A. In response to the Rebuttal Testimony of Staff and RUCO, my Rejoinder Testimony emphasizes the necessity to ensure that the ROE for APS meets the end-result test required by regulatory policy, with the specific risks and challenges faced by APS justifying an ROE that exceeds the historical average for other utilities. Moreover, because the end-result test must consider the utility's actual ability to earn the allowed rate of return, it is imperative to consider the impact of attrition when establishing an ROE for APS. Finally, I concluded that my reference to the methods previously adopted by the Commission serves as a useful benchmark in evaluating the reasonableness of Staff's and RUCO's ROE recommendation in this case. The fact that Staff's recommended ROE for APS falls *below* what was approved by the ACC in August 2006 for a lower-risk water utility illustrates the fact that Mr. Parcell's recommendation is significantly downward-biased.

III. THE ROE FOR APS MUST RECOGNIZE FINANCIAL REALITIES

Q. DOES THE SURREBUTTAL TESTIMONY OF MR. PARCELL OR MR. HILL ADDRESS THE FUNDAMENTAL ISSUE IN THIS CASE?

A. No. Mr. Parcell and Mr. Hill focus almost exclusively on theoretical arguments surrounding the application of alternative approaches to estimate the cost of equity. These discussions debate detailed technical questions surrounding the growth rates used in the discounted cash flow ("DCF") model, for example, or the market risk premium necessary to apply the Capital Asset Pricing Model ("CAPM"), and even include a lengthy review of the findings from a single academic paper. Of course, experts on opposite sides of an issue are apt to have differing views on how best to apply accepted models to estimate the cost of equity, and my opinions on these details are fully articulated and supported in my Direct and Rebuttal testimony. But focusing on these more technical debates masks the salient issue; namely, "What is a fair ROE for APS, given its risks and the financial realities that the Company faces?" The answer to this

question is of more than theoretical interest. If the allowed ROE does not maintain the ability of APS to obtain capital on reasonable terms from real world investors, then the real world customers of APS will suffer the consequences.

Q. DO YOU AGREE WITH MR. PARCELL'S ARGUMENT THAT AUTHORIZED RETURNS DON'T SUPPORT YOUR RECOMMENDED ROE?

A. No. In his Surrebuttal Testimony, Mr. Parcell cited the 10.69% and 10.57% average authorized returns for electric utilities in 2006 that I referenced on Rebuttal, claiming that this data does not support a higher return for APS.[1] First, I made reference to these benchmarks in order to illustrate that Mr. Parcell's 10.25% ROE is significantly downward-biased, while Mr. Hill's 9.25% recommendation is far beyond the realm of reasonableness. Second, as developed in my Direct and Rebuttal Testimony, when considered along with the financial realities faced by APS, the upward trend in bond yields during 2006, and the current capital market requirements reflected in my analyses, these benchmarks are entirely consistent with my recommended ROE.

In fact, there are several key distinctions between APS and other electric utilities that justify supportive regulatory treatment, including the Company's requested ROE. As explained in my prior testimony in this case, and as documented in the testimony of other Company witnesses, APS is facing severe financial pressures because of its inability to recover the costs of providing service, including a fair ROE, on a timely basis. As a result, Standard & Poor's ("S&P") and Fitch Ratings, Ltd. ("Fitch") have assigned APS the lowest rating on the investment grade scale and all of the major bond rating agencies, including Moody's Investors Service ("Moody's") have noted that the Company's financial metrics are under pressure. Moody's has assigned a "negative" outlook to APS, indicating the potential for future downgrades, and both S&P and Fitch

[1] Parcell Surrebuttal at 2.

have explicitly noted the need for supportive regulatory treatment in order to bolster the Company's finances and maintain current ratings.

An outcome in this case that deviates significantly from investors' expectations and requirements has the very real danger of pushing APS' credit ratings over the precipice and into speculative, or "junk" bond territory. Junk bond ratings imply an altogether different level of investment risks and would constitute a significant erosion of APS' ability to raise capital on reasonable terms, with the ultimate result being higher costs to customers.

Q. WHAT OTHER FACTORS MAKE IT IMPERATIVE THAT APS BE ALLOWED AN ROE THAT EXCEEDS THE AVERAGE FOR OTHER ELETRIC UTILITIES?

A. Aside from the need to maintain or enhance credit ratings, APS faces the challenges of a swiftly growing service territory that requires the commitment of significant new investment in order to meet customers' demands. As a result, at the very same time that the Company is confronting the impact of inadequate rates and an inability to earn investors' required return, it also must raise significant capital to meet its service obligations. Setting an ROE that fails to provide investors with returns commensurate with other utilities would send the wrong signal at a time when access to capital is crucial for the Company and its customers.

Apart from the capital requirements of its growing service area, S&P, Moody's, and Fitch have also recognized other inherent risks that must be considered in establishing APS' ROE relative to other utilities. For example, Fitch has noted the risks associated with "high and volatile variable costs," which are only compounded by a relatively limited Power Supply Adjustor. In addition, APS must contend with the impact of attrition, which pervasively erodes the Company's ability to earn returns commensurate

with those of other firms that are competing for investors' capital. Taken together, and in tandem with my analyses of investors' current requirements, these considerations all support an ROE for APS that is above the average for electric utilities as a whole.

IV. IMPACT OF ATTRITION IS PROPERLY CONSIDERED

Q. DO STAFF OR RUCO DENY THAT ATTRITION PREVENTS APS FROM HAVING A REALISTIC OPPORTUNITY TO EARN ITS AUTHORIZED RETURN?

A. No. No party to this case seeks to argue that APS is not impacted by attrition. In fact, Mr. Parcell granted that he also "cited this State's regulatory environment in my direct testimony" and noted that Staff had recommended an "enhanced" methodology to recover fuel and purchased power costs.[2] But as Mr. Hill noted, there is more to attrition than power cost recovery. Mr. Hill explained the disconnect between a utility's revenues and costs that occurs during a cycle of construction and capital additions and concluded that:

> ... I believe it is reasonable to investigate and perhaps adjust certain aspects of the manner in which rates are set during a time of substantial capital additions.[3]

Further, Mr. Hill readily granted that "administrative aspects of the ratemaking process" (*i.e.* regulatory lag) could cause APS to under-recover its allowed return.

Q. WHAT BASIS DID STAFF AND RUCO PROVIDE FOR IGNORING THE IMPACT OF ATTRITION?

A. Staff and RUCO's chief argument against considering the impact of attrition when setting an ROE for APS is that the Company did not propose such an adjustment in its direct case. While granting that construction and regulatory lag can prevent a utility

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[2] Parcell Surrebuttal at 4. Mr. Parcell's Direct Testimony at pp. 14-15 documented the investment community's perception that APS' power supply adjustor is "weak" and leaves the Company exposed to cash flow volatility.

[3] Hill Surrebuttal at 6.

from earning its allowed return, Mr. Hill opined that an argument supporting an attrition adjustment "constitutes additional direct testimony."[4] Similarly, Mr. Dittmer bemoaned "a lack of forewarning in the Company's direct case" in explaining Staff's failure to consider the impact of their recommendations for APS on a forward-looking basis.[5] Mr. Parcell too expressed his disagreement at introducing a "new issue" at this stage of the proceeding.[6]

Q. IS ATTRITION A "NEW ISSUE"?

A. No. My Direct Testimony noted the impact of regulatory lag and cost recovery in assessing a fair ROE for APS,[7] and the impact of attrition, especially as it relates to power cost recovery, has been an ongoing issue at the ACC. Moreover, attrition and regulatory lag have been recognized by the investment community as significant concerns long before Staff and RUCO filed their Direct Testimony in this case. While Staff and RUCO are correct that an attrition adjustment was not included as part of APS' direct case, this is because the direct case was premised on my recommended ROE of 11.5% and the other features of the Company's request that were intended to restore investor confidence. In response to the significantly lower ROE recommendations of Staff and RUCO, and in light of the Commissions' expressions of concern about APS' credit standing, my rebuttal testimony proposed an attrition adjustment as a way to preserve the Company's financial integrity and meet the end-result test required by established regulatory principles if proposals by Staff and RUCO were adopted. There is nothing "new" about the regulatory requirement that a utility be granted an opportunity to actually earn its required rate of return, and my proposed attrition

[4] Hill Surrebuttal at 28.
[5] Dittmer Surrebuttal at 7.
[6] Parcell Surrebuttal at 2.
[7] See, *e.g.*, Avera Direct at 65-66.

adjustment simply responds to the inability of Staff and RUCO's recommendations to meet this fundamental requirement.

Q. WHAT ABOUT MR. HILL'S CLAIM THAT HE HAS ASSESSED THE ADEQUACY OF HIS RECOMMENDATIONS?

A. Mr. Hill states that his overall cost of capital, including his 9.25% ROE, will allow APS to improve its coverage ratio and he makes the incredible claim that his anemic return recommendation "affords the Company an opportunity to improve its financial position."[8] First, Mr. Hill's focus on a single financial metric – the pre-tax coverage ratio – says nothing about the overall question of the Company's financial integrity, as evidenced by the warnings of the major rating agencies that a lack of regulatory support in this case will undermine APS credit standing and could lead to lower ratings. More importantly, Mr. Hill's "test" is meaningless because it assumes that APS will actually earn its allowed return. As S&P noted, the investment community is focused on actual earnings, not the make-believe parameters underlying Mr. Hill's conclusions:

> Although a higher authorized return on equity (ROE) may theoretically improve a utility's cash flow, a company's ability to actually earn the authorized ROE is more important for overall creditworthiness. The ability to earn an authorized ROE depends on adjustments included in rate-case decisions, and other regulatory mechanisms such as fuel-adjustment clauses.[9]

As documented in Schedule F-1 of the Company's January 31, 2006 filing, this key assumption underlying Mr. Hill's so-called "test" is at odds with the realities faced by APS, and as the bond rating agencies have highlighted, investors are also well aware of the difficulties that attrition poses for the Company.

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[8] Hill Surrebutal at 3.

[9] Standard & Poor's Corporation, "How Returns On Equity Factor Into U.S. Utilities' Creditworthiness," *RatingsDirect* (June 14, 2005).

Regulatory policy holds that a utility must be granted an opportunity to actually earn the allowed rate of return. Mr. Hill turns this test on its head, by first assuming that APS *will* actually earn his recommended ROE, and then claiming a single financial ratio as "proof" that his recommendations are sound. While Mr. Hill does not deny that attrition is a force that impacts a utility's ability to earn its allowed return, he completely ignores this reality in evaluating his own recommendations. As a result, his "test" is inconsistent with the real world standards required of an authorized ROE.

V. APPLICATION OF STAFF'S METHODS AS A BENCHMARK

Q. HAVE MR. PARCELL OR MR. HILL PROVIDED ANY EVIDENCE TO JUSTIFY IGNORING THE RESULTS OF STAFF'S OWN METHODS IN ESTIMATING THE ROE FOR APS?

A. No. In my Rebuttal Testimony, I explained that application of the same methods advanced by the ACC Staff and adopted by the Commission just months ago imply an ROE for APS of 11.2%, before considering an adjustment for flotation costs.[10] Neither Mr. Parcell nor Mr. Hill have meaningfully addressed the discord between their recommendations in this case and the results implied by Staff's approaches in a recent case.

Q. WHAT ABOUT MR. PARCELL'S OBSERVATION (P. 11) THAT HIS CONCLUSIONS "ARE VERY SIMILAR" TO THOSE OF STAFF WITNESS ROGERS?

A. Mr. Parcell's observation is meaningless because it ignores fundamental differences between the water utilities that were the focus of Mr. Rogers' testimony in Docket No. W-01303A-05-0405, on the one hand, and electric utilities, such as APS, on the other. While Mr. Parcell urges the Commission to compare his "bottom line" recommendation with that of Mr. Rogers, this is comparing apples to oranges. Indeed, if Mr. Parcell's

[10] Avera Rebuttal at 28.

logic were true, the ACC could simply make one ROE finding and apply it across-the-board to all utilities, which is clearly nonsensical.

Consider the application of the CAPM, for example. Mr. Parcell, Mr. Hill, and I all agree that in applying the CAPM to estimate the cost of equity, the relevant measure of investment risk is beta. Beta reflects the tendency of a stock's price to follow changes in the market. A higher beta being indicative of higher risk and, correspondingly, a higher required return. The average beta for the group of water utilities referenced by Mr. Rogers was 0.71.[11] Meanwhile, Mr. Parcell indicated that the average beta for his comparison group in this case was 0.89, with Pinnacle West's beta being 0.95.[12] This comparison demonstrates that Mr. Parcell's comparison group is significantly more risky than the water utility group referenced by Mr. Rogers, which implies an ROE for APS that is considerably higher than the 10.4% recently authorized for the Paradise Valley Water District.

Q. APART FROM BETA, IS THERE OTHER EVIDENCE THAT CONFIRMS THIS CONCLUSION.

A. Yes. In a recent review of credit conditions in the water utility industry entitled, "Water Utilities Remain Islands of Stability," S&P noted that "U.S. water utilities have remained one of the most stable and highly rated sectors of the U.S. utility industry."[13] S&P concluded that:

> The U.S. water utility sector has long held a rating advantage over other U.S. utilities as a whole. For the year ended Dec. 31, 2005, 10 of the 11 (94%) water utilities had ratings in the "A" category or better, in contrast to only 34% of all U.S. utilities.[14]

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[11] Docket No. W-01303A-05-0405, Direct Testimony of Dennis Rogers at 29.

[12] Parcell Direct at Schedule 13.

[13] Standard & Poor's Corporation, "Water Utilities Remain Islands of Stability," *RatingsDirect* (Feb. 15, 2006).

[14] *Id.*

S&P went on to note that the *business profile* ranking – the measure of relative business risk referenced by Mr. Hill – averaged "between '2' and '3' (on a 10-point scale where '1' is excellent."[15] Meanwhile, as discussed in my Rebuttal Testimony, S&P has assigned a *business profile* ranking of "6" to APS, indicating substantially greater business risks than for the water utilities that were the subject of Mr. Rogers' recommendation.

Despite the fact that capital costs have increased since Mr. Rogers filed his testimony, and that APS and Mr. Parcell's comparison group both have significantly higher investment risks than a water utility, Mr. Parcell's recommended ROE falls *below* the 10.4% ROE approved by the ACC just two months ago. The only thing this comparison demonstrates is the inadequacy of Mr. Parcell's 10.25% ROE for APS. Contrary to Mr. Parcell's claim that I have taken Mr. Rogers' testimony out of context, I have put it *into context* by applying Staff's methods using capital market data specific to Mr. Parcell's own comparison group, and these analyses result in an average ROE of 11.2%.

Q. DID MR. HILL PROVIDE ANY BASIS FOR IGNORING THE RESULTS OF THE ACC STAFF'S ANALYSES?

A. No. Mr. Hill asserts (pp. 21-22) that "Dr. Avera's multi-stage DCF" is flawed. First, I would reiterate that the multi-stage model applied in my Rebuttal Testimony is not something of my own creation. Rather, it is the same approach utilized by the ACC Staff and adopted without discussion by the Commission in August 2006. Despite the fact that this method, including the underlying long-term growth rate, was accepted

[15] *Id.*

without comment by the ACC a scant 2 months ago, Mr. Hill arbitrarily cuts this growth rate in half.[16]

Meanwhile, Mr. Hill made no mention of Staff's risk premium applications whatsoever, and instead focused on the details underlying a selected few journal articles and a single analyst report. And while I grant Mr. Hill's observation (p. 16) that it was incorrect of me to include an inflation premium in interpreting the results of the *Mehra* study, this has no bearing on my conclusions.[17] In fact, no selected historical study, or group of studies, is a substitute for an analysis of investors' current expectations in the capital markets. Nor does a single figure from one securities analyst report provide compelling evidence concerning the extent to which an ROE recommendation meets the threshold test of reasonableness required by regulatory policy.

As discussed in my Direct and Rebuttal Testimony, analyses of the cost of equity that incorporate current expectations, including the methods previously adopted by the Staff and approved by the ACC, uniformly and conclusively demonstrate that Mr. Hill's recommended ROE falls far short of investors' required return.

VI. CONCLUSION

Q. DOES THAT CONCLUDE YOUR REJOINDER TESTIMONY IN THIS PROCEEDING?

A. Yes.

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[16] The only support Mr. Hill offered for this adjustment was a historical comparison of growth in GDP with historical growth rates for utilities. As discussed repeatedly, however, in applying the DCF model, it is investors' *expectations* that are key, not historical relationships. Mr. Hill's comparison says nothing about the ability of the ACC Staff's growth rate to track investors' long-term expectations for utilities into the future.

[17] Multiplying the 6.9% risk premium over T-bills from the *Mehra* article by the average beta of 0.83 from Mr. Hill's Schedule 8, and then adding the resulting 5.7% risk premium to the average yield on 3-month bills for July 2006 of approximately 5% results in an indicated cost of equity for Mr. Hill's comparison group of 10.7%, which significantly exceeds his recommendation.

	January	October	Change (basis points)
DCF			
Dividend Yield	3.5%	3.6%	10
Earnings Growth			
IBES	5.4%	6.2%	80
Value Line	5.5%	5.8%	30
First Call	5.5%	5.9%	40
Zacks	5.7%	6.6%	90
Reuters	5.7%	6.2%	50
B xR Growth	4.6%	5.2%	60
Risk Premium			
Authorized			
Current Yield	10.7%	11.0%	30
Projected Yield	11.4%	11.4%	-
Realized			
Current Yield	9.8%	10.4%	60
Projected Yield	11.0%	11.1%	10
CAPM - Forward			
Current Yield	12.5%	13.3%	80
Projected Yield	12.6%	13.3%	70
CAPM - Historical			
Current Yield	10.9%	11.8%	90
Projected Yield	11.9%	12.3%	40
Comparable Earnings			
Mean	17.4%	16.5%	(90)
Median	15.5%	15.4%	(10)

EXHIBIT
APS 44
admitted

BBB Bond Yield

Sep-05	5.83%
Oct-05	6.08%
Nov-05	6.19%
Dec-05	6.14%
Jan-06	6.06%
Feb-06	6.11%
Mar-06	6.26%
Apr-06	6.54%
May-06	6.59%
Jun-06	6.61%
Jul-06	6.61%
Aug-06	6.43%
Sep-06	6.26%
Change (Sep 05 - Sep 06)	0.43%

CONSTANT GROWTH DCF MODEL

EXPECTED DIVIDEND YIELD

Company	(a) Recent Price	(a) Estimated Dividends Next 12 Mos.	Dividend Yield
Black Hills Corp.	$ 36.42	$ 1.35	3.7%
Edison International	$ 42.52	$ 1.14	2.7%
Hawaiian Electric	$ 28.10	$ 1.24	4.4%
IDACORP, Inc.	$ 37.14	$ 1.20	3.2%
MDU Resources Group	$ 25.10	$ 0.54	2.2%
Pinnacle West Capital	$ 43.44	$ 2.10	4.8%
PNM Resources Group	$ 27.13	$ 0.90	3.3%
Puget Energy, Inc.	$ 22.40	$ 1.00	4.5%
Sempra Energy	$ 47.39	$ 1.22	2.6%
Xcel Energy	$ 20.45	$ 0.90	4.4%
Average			**3.6%**

(a) The Value Line Investment Survey, Summary and Index (Aug. 11, 2006).

CONSTANT GROWTH DCF MODEL

PROJECTED GROWTH RATES

	Earnings				
	(a)	(b)	(c)	(d)	(e)
Company	IBES	Value Line	First Call	Zacks	Reuters
Black Hills Corp.	5.0%	6.5%	4.5%	6.0%	4.5%
Edison International	9.0%	8.0%	9.0%	7.7%	7.8%
Hawaiian Electric	4.0%	3.0%	3.0%	8.0%	4.3%
IDACORP, Inc.	5.0%	4.5%	5.0%	4.7%	4.7%
MDU Resources Group	7.0%	8.0%	6.5%	8.2%	7.2%
Pinnacle West Capital	6.0%	6.0%	6.0%	6.8%	5.8%
PNM Resources Group	12.0%	5.5%	12.0%	8.3%	11.5%
Puget Energy, Inc.	4.0%	5.0%	4.0%	7.0%	5.1%
Sempra Energy	6.0%	5.5%	4.6%	5.4%	6.2%
Xcel Energy	4.0%	6.0%	4.0%	4.3%	4.7%
Average	**6.2%**	**5.8%**	**5.9%**	**6.6%**	**6.2%**

NA -- Not Available

(a) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (July 2006).
(b) The Value Line Investment Survey (Aug. 11, 2006).
(c) First Call Earnings Estimates from www.finance.yahoo.com (Retrieved Oct. 19, 2006).
(d) Zacks Investment Research growth estimates from www.zacks.com (Retrieved Oct. 20, 2006
(e) Reuters earnings growth rates from www.investor.reuters.com (Oct. 20, 2006).

CONSTANT GROWTH DCF MODEL

SUSTAINABLE GROWTH RATE

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections 2009-11			2005		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
Black Hills Corp.	$2.75	$1.48	$28.00	$22.29	4.7%	1.0228	46.2%	10.0%	4.6%	0.15%	4.8%
Edison International	$3.45	$1.40	$30.80	$20.30	8.7%	1.0417	59.4%	11.7%	6.9%	0.01%	6.9%
Hawaiian Electric	$1.75	$1.24	$17.00	$15.02	2.5%	1.0124	29.1%	10.4%	3.0%	0.12%	3.2%
IDACORP, Inc.	$2.00	$1.20	$28.25	$24.04	3.3%	1.0161	40.0%	7.2%	2.9%	0.24%	3.1%
MDU Resources Group	$2.00	$0.70	$17.00	$10.43	10.3%	1.0488	65.0%	12.3%	8.0%	1.67%	9.7%
Pinnacle West Capital	$3.55	$2.43	$40.20	$34.57	3.1%	1.0151	31.5%	9.0%	2.8%	0.01%	2.8%
PNM Resources Group	$1.90	$1.10	$23.00	$18.70	4.2%	1.0207	42.1%	8.4%	3.6%	0.45%	4.0%
Puget Energy, Inc.	$1.75	$1.10	$21.25	$17.52	3.9%	1.0193	37.1%	8.4%	3.1%	0.17%	3.3%
Sempra Energy	$4.75	$1.36	$41.00	$23.95	11.4%	1.0537	71.4%	12.2%	8.7%	0.35%	9.1%
Xcel Energy	$1.75	$1.10	$16.00	$13.37	3.7%	1.0180	37.1%	11.1%	4.1%	0.52%	4.7%
Average											**5.2%**

(a) The Value Line Investment Survey (Aug. 11, 2006).
(b) Annual growth in book value per share from 2005 to 2009-11.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (EPS/2009-11 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).

AUTHORIZED RATES OF RETURN - CURRENT YIELD

YEAR	(a) ALLOWED ROE	(b) AVERAGE PUBLIC UTILITY BOND YIELD	RISK PREMIUM
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.14%	3.29%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.50%	3.66%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
Average		9.46%	3.22%

Implied Cost of Equity	
Average Yield over Study Period	9.46%
Sep. 2006 Average Utility Bond Yield (c)	6.02%
Change in Bond Yield	-3.44%
Risk Premium/Interest Rate Relationship (d)	-43.14%
Adjustment to Average Risk Premium	1.48%
Average Risk Premium over Study Period	3.22%
Adjusted Risk Premium	4.70%
Sep. 2006 Triple-B Utility Bond Yield	6.26%
Implied Cost of Equity	**10.96%**

(a) Regulatory Research Associates, Major Rate Case Decisions, January 1990 - December 2005, *Regulatory Focus* (January 2006); Major Rate Case Decisions, *Regulatory Focus*, (January 16, 1990); Argus, *UtilityScope Regulatory Service* (January 1986).

(b) Moody's *Public Utility Manual* (2003); Mergent *Bond Record* (Jan. 2006).

(c) Moody's *Credit Perspectives* (Oct. 16, 2006).

(d) Coefficient of regression between bond yields and equity risk premiums over the study period.

AUTHORIZED RATES OF RETURN - PROJECTED YIELD

YEAR	(a) ALLOWED ROE	(b) AVERAGE PUBLIC UTILITY BOND YIELD	RISK PREMIUM
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.14%	3.29%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.50%	3.66%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
Average		9.46%	3.22%

Implied Cost of Equity	
Average Yield over Study Period	9.46%
2007 Average Utility Bond Yield (c)	6.70%
Change in Bond Yield	-2.76%
Risk Premium/Interest Rate Relationship (d)	-43.14%
Adjustment to Average Risk Premium	1.19%
Average Risk Premium over Study Period	3.22%
Adjusted Risk Premium	4.41%
2007 Triple-B Utility Bond Yield	7.00%
Implied Cost of Equity	**11.41%**

(a) Regulatory Research Associates, Major Rate Case Decisions, January 1990 - December 2005, *Regulatory Focus* (January 2006); Major Rate Case Decisions, *Regulatory Focus*, (January 16, 1990); Argus, *UtilityScope Regulatory Service* (January 1986).

(b) Moody's *Public Utility Manual* (2003); Mergent *Bond Record* (Jan. 2006).

(c) Based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 30-Year Focus* (First-Quarter 2006), EIA, *Annual Energy Outlook 2006* (Feb. 2006), and Blue Chip Financial Forecasts (July 1, 2006).

(d) Coefficient of regression between bond yields and equity risk premiums over the study period.

REALIZED RATES OF RETURN - CURRENT YIELD

	S&P ELECTRIC UTILITIES (a)			AVERAGE PUBLIC UTILITY BONDS (b)		
	CLOSE PRICE	DIV	ANNUAL REALIZED RETURN	CLOSE YIELD	PRICE	ANNUAL REALIZED RETURN
1945	$16.34		(c)	2.79%		(d)
1946	$15.53	$0.73	-0.49%	2.77%	$100.36	3.15%
1947	$12.89	$0.75	-12.17%	3.02%	$95.66	-1.57%
1948	$12.37	$0.71	1.47%	3.06%	$99.31	2.33%
1949	$14.60	$0.80	24.49%	2.79%	$104.81	7.87%
1950	$14.49	$0.88	5.27%	2.87%	$98.59	1.38%
1951	$16.07	$0.92	17.25%	3.24%	$93.73	-3.40%
1952	$18.28	$0.95	19.66%	3.19%	$100.85	4.09%
1953	$18.97	$0.99	9.19%	3.37%	$96.99	0.18%
1954	$22.39	$1.03	23.46%	3.10%	$104.65	8.02%
1955	$24.06	$1.09	12.33%	3.31%	$96.47	-0.43%
1956	$23.61	$1.13	2.83%	3.93%	$90.24	-6.45%
1957	$24.85	$1.19	10.29%	4.29%	$94.54	-1.53%
1958	$33.14	$1.24	38.35%	4.39%	$98.50	2.79%
1959	$33.42	$1.30	4.77%	4.86%	$93.28	-2.33%
1960	$39.35	$1.37	21.84%	4.58%	$104.12	8.98%
1961	$49.28	$1.44	28.89%	4.62%	$99.41	3.99%
1962	$48.60	$1.52	1.70%	4.41%	$103.14	7.76%
1963	$51.97	$1.63	10.29%	4.49%	$98.81	3.22%
1964	$58.21	$1.74	15.36%	4.54%	$99.26	3.75%
1965	$58.05	$1.90	2.99%	4.82%	$95.98	0.52%
1966	$53.49	$2.04	-4.34%	5.65%	$89.03	-6.15%
1967	$49.90	$2.16	-2.67%	6.57%	$88.85	-5.50%
1968	$51.95	$2.27	8.66%	6.85%	$96.69	3.26%
1969	$42.65	$2.33	-13.42%	8.39%	$84.09	-9.06%
1970	$45.62	$2.40	12.59%	8.45%	$99.38	7.77%
1971	$44.18	$2.47	2.26%	7.92%	$105.70	14.15%
1972	$43.50	$2.53	4.19%	7.48%	$104.91	12.83%
1973	$32.85	$2.51	-18.71%	8.17%	$92.74	0.22%
1974	$22.03	$2.49	-25.36%	10.02%	$83.23	-8.60%
1975	$30.56	$2.57	50.39%	9.87%	$101.38	11.40%
1976	$35.17	$2.58	23.53%	8.61%	$112.78	22.65%
1977	$35.67	$2.74	9.21%	8.65%	$99.60	8.21%
1978	$31.38	$2.94	-3.78%	9.67%	$90.50	-0.85%
1979	$28.44	$3.10	0.51%	11.68%	$83.88	-6.45%
1980	$27.19	$3.20	6.86%	14.48%	$81.32	-7.00%
1981	$29.33	$3.42	20.45%	15.77%	$92.03	6.51%
1982	$36.15	$3.62	35.59%	13.55%	$115.70	31.47%
1983	$37.14	$3.84	13.36%	13.48%	$100.50	14.05%
1984	$42.26	$4.06	24.72%	12.96%	$103.82	17.30%
1985	$48.82	$4.15	25.34%	10.82%	$118.26	31.22%
1986	$58.31	$4.21	28.06%	8.96%	$118.33	29.15%
1987	$49.78	$4.34	-7.19%	10.99%	$82.89	-8.15%
1988	$53.87	$4.37	16.99%	10.02%	$108.79	19.78%
1989	$66.55	$4.28	31.48%	9.31%	$106.80	16.82%
1990	$63.47	$4.45	2.06%	9.57%	$97.56	6.87%
1991	$77.25	$4.57	28.91%	8.76%	$108.11	17.68%
1992	$76.78	$4.68	5.45%	8.36%	$104.14	12.90%
1993	$81.71	$4.71	12.56%	7.33%	$111.65	20.01%
1994	$66.30	$4.65	-13.17%	8.79%	$85.41	-7.26%
1995	$81.62	$4.67	30.15%	7.21%	$118.07	26.86%
1996	$76.75	$4.61	-0.32%	7.58%	$95.90	3.11%
1997	$91.49	$4.47	25.03%	7.16%	$104.82	12.40%
1998	$100.86	$4.39	15.04%	6.84%	$103.78	10.94%
1999	$77.42	$4.35	-18.93%	8.04%	$87.23	-5.93%
2000	$113.00	$4.42	51.67%	7.79%	$102.72	10.76%
2001	$99.70	$3.56	-8.62%	7.86%	$99.24	7.03%
2002	$77.85	$3.88	-18.02%	7.13%	$108.41	16.27%
2003	$92.63	$3.47	23.45%	6.35%	$109.60	17.46%
2004	$112.82	$3.78	25.88%	5.93%	$105.40	12.53%
2005	$128.07	$4.49	17.49%	5.83%	$101.34	7.70%
Average			**10.92%**			**6.78%**

Realized Rates of Return	
S&P Electric Utilities	10.92%
Average Public Utility Bonds	6.78%
Equity Risk Premium	4.14%
April 2006 Triple-B Utility Bond Yield (e)	6.26%
Implied Cost of Equity	**10.40%**

(a) S&P's *Security Price Index Record* (2002), *The Analysts' Handbook* (1967, 1999, 2001, 2005, Monthly Supplement (March 2006).
(b) Average public utility bond yields for December from Mergent *Public Utility Manual* (2003), Mergent *Bond Record* (Jan. 2006).
(c) Computed by adding gain or loss (ending stock price - beginning stock price) to annual dividends and dividing by beginning stock price.
(d) Computed as sum of capital gain or loss plus interest income, divided by beginning price.
(e) Moody's *Credit Perspectives* (May 8, 2006).

REALIZED RATES OF RETURN - PROJECTED YIELD

	S&P ELECTRIC UTILITIES (a)			AVERAGE PUBLIC UTILITY BONDS (b)		
	CLOSE PRICE	DIV	ANNUAL REALIZED RETURN	CLOSE YIELD	PRICE	ANNUAL REALIZED RETURN
1945	$16.34		(c)	2.79%		(d)
1946	$15.53	$0.73	-0.49%	2.77%	$100.36	3.15%
1947	$12.89	$0.75	-12.17%	3.02%	$95.66	-1.57%
1948	$12.37	$0.71	1.47%	3.06%	$99.31	2.33%
1949	$14.60	$0.80	24.49%	2.79%	$104.81	7.87%
1950	$14.49	$0.88	5.27%	2.87%	$98.59	1.38%
1951	$16.07	$0.92	17.25%	3.24%	$93.73	-3.40%
1952	$18.28	$0.95	19.66%	3.19%	$100.85	4.09%
1953	$18.97	$0.99	9.19%	3.37%	$96.99	0.18%
1954	$22.39	$1.03	23.46%	3.10%	$104.65	8.02%
1955	$24.06	$1.09	12.33%	3.31%	$96.47	-0.43%
1956	$23.61	$1.13	2.83%	3.93%	$90.24	-6.45%
1957	$24.85	$1.19	10.29%	4.29%	$94.54	-1.53%
1958	$33.14	$1.24	38.35%	4.39%	$98.50	2.79%
1959	$33.42	$1.30	4.77%	4.86%	$93.28	-2.33%
1960	$39.35	$1.37	21.84%	4.58%	$104.12	8.98%
1961	$49.28	$1.44	28.89%	4.62%	$99.41	3.99%
1962	$48.60	$1.52	1.70%	4.41%	$103.14	7.76%
1963	$51.97	$1.63	10.29%	4.49%	$98.81	3.22%
1964	$58.21	$1.74	15.36%	4.54%	$99.26	3.75%
1965	$58.05	$1.90	2.99%	4.82%	$95.98	0.52%
1966	$53.49	$2.04	-4.34%	5.65%	$89.03	-6.15%
1967	$49.90	$2.16	-2.67%	6.57%	$88.85	-5.50%
1968	$51.95	$2.27	8.66%	6.85%	$96.69	3.26%
1969	$42.65	$2.33	-13.42%	8.39%	$84.09	-9.06%
1970	$45.62	$2.40	12.59%	8.45%	$99.38	7.77%
1971	$44.18	$2.47	2.26%	7.92%	$105.70	14.15%
1972	$43.50	$2.53	4.19%	7.48%	$104.91	12.83%
1973	$32.85	$2.51	-18.71%	8.17%	$92.74	0.22%
1974	$22.03	$2.49	-25.36%	10.02%	$83.23	-8.60%
1975	$30.56	$2.57	50.39%	9.87%	$101.38	11.40%
1976	$35.17	$2.58	23.53%	8.61%	$112.78	22.65%
1977	$35.67	$2.74	9.21%	8.65%	$99.60	8.21%
1978	$31.38	$2.94	-3.78%	9.67%	$90.50	-0.85%
1979	$28.44	$3.10	0.51%	11.68%	$83.88	-6.45%
1980	$27.19	$3.20	6.86%	14.48%	$81.32	-7.00%
1981	$29.33	$3.42	20.45%	15.77%	$92.03	6.51%
1982	$36.15	$3.62	35.59%	13.55%	$115.70	31.47%
1983	$37.14	$3.84	13.36%	13.48%	$100.50	14.05%
1984	$42.26	$4.06	24.72%	12.96%	$103.82	17.30%
1985	$48.82	$4.15	25.34%	10.82%	$118.26	31.22%
1986	$58.31	$4.21	28.06%	8.96%	$118.33	29.15%
1987	$49.78	$4.34	-7.19%	10.99%	$82.89	-8.15%
1988	$53.87	$4.37	16.99%	10.02%	$108.79	19.78%
1989	$66.55	$4.28	31.48%	9.31%	$106.80	16.82%
1990	$63.47	$4.45	2.06%	9.57%	$97.56	6.87%
1991	$77.25	$4.57	28.91%	8.76%	$108.11	17.68%
1992	$76.78	$4.68	5.45%	8.36%	$104.14	12.90%
1993	$81.71	$4.71	12.56%	7.33%	$111.65	20.01%
1994	$66.30	$4.65	-13.17%	8.79%	$85.41	-7.26%
1995	$81.62	$4.67	30.15%	7.21%	$118.07	26.86%
1996	$76.75	$4.61	-0.32%	7.58%	$95.90	3.11%
1997	$91.49	$4.47	25.03%	7.16%	$104.82	12.40%
1998	$100.86	$4.39	15.04%	6.84%	$103.78	10.94%
1999	$77.42	$4.35	-18.93%	8.04%	$87.23	-5.93%
2000	$113.00	$4.42	51.67%	7.79%	$102.72	10.76%
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2002	$77.85	$3.88	-18.02%	7.13%	$108.41	16.27%
2003	$92.63	$3.47	23.45%	6.35%	$109.60	17.46%
2004	$112.82	$3.78	25.88%	5.93%	$105.40	12.53%
2005	$128.07	$4.49	17.49%	5.83%	$101.34	7.70%
Average			**10.92%**			**6.78%**

Realized Rates of Return	
S&P Electric Utilities	10.92%
Average Public Utility Bonds	6.78%
Equity Risk Premium	4.14%
2007 Triple-B Utility Bond Yield (e)	7.00%
Implied Cost of Equity	**11.14%**

(a) S&P's *Security Price Index Record* (2002), *The Analysts' Handbook* (1967, 1999, 2001, 2005, Monthly Supplement (March 2006).
(b) Average public utility bond yields for December from Mergent *Public Utility Manual* (2003), Mergent *Bond Record* (Jan. 2006).
(c) Computed by adding gain or loss (ending stock price - beginning stock price) to annual dividends and dividing by beginning stock price.
(d) Computed as sum of capital gain or loss plus interest income, divided by beginning price.
(e) Based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 30-Year Focus* (First-Quarter 2006), EIA, *Annual Energy Outlook 2006* (Feb. 2006), and Blue Chip Financial Forecasts (July 1, 2006).

CAPITAL ASSET PRICING MODEL

FORWARD-LOOKING RISK PREMIUM - CURRENT YIELD

Market Rate of Return		
Dividend Yield (a)	1.8%	
Growth Rate (b)	11.8%	
Market Return (c)		13.6%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.9%
Market Risk Premium (e)		8.7%
Utility Proxy Group Beta (f)		0.97
Utility Proxy Group Risk Premium (g)		8.4%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.9%
Implied Cost of Equity (h)		**13.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Oct. 19, 2006).
(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* (Oct. 2006) and www.valueline.com (Retreived Oct. 19, 2006).
(c) (a) + (b)
(d) Average of the daily yields on 20-year Treasury bonds for Sep. 2006 reported by the U.S. Department of the Treasury at www.treas.gov.
(e) (c) - (d).
(f) The Value Line Investment Survey (Aug. 11, 2006).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

FORWARD-LOOKING RISK PREMIUM - PROJECTED YIELD

Market Rate of Return		
Dividend Yield (a)	1.8%	
Growth Rate (b)	11.8%	
Market Return (c)		13.6%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		5.4%
Market Risk Premium (e)		8.2%
Utility Proxy Group Beta (f)		0.97
Utility Proxy Group Risk Premium (g)		7.9%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		5.4%
Implied Cost of Equity (h)		**13.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Oct. 19, 2006).
(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* (Oct. 2006) and www.valueline.com (Retreived Oct. 19, 2006).
(c) (a) + (b)
(d) Projected yield on 20-year Treasury bonds for 2007 based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 30-Year Focus* (First-Quarter 2006), Energy Information Administration, *Annual Energy Outlook 2006* (Jan. 2006), and Blue Chip Financial Forecasts (July 1, 2006).
(e) (c) - (d).
(f) The Value Line Investment Survey (Aug 11, 2006).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

HISTORICAL RISK PREMIUM - CURRENT YIELD

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.1%
Utility Proxy Group Beta (b)	0.97
Utility Proxy Group Risk Premium (c)	6.9%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	4.9%
Implied Cost of Equity (e)	**11.8%**

(a) Arithmetic mean risk premium on Large Company Stocks from 1926-2005 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at Appendix C, Table C-1, p. 262.

(b) The Value Line Investment Survey (Aug. 11, 2006).

(c) (a) x (b).

(d) Average of the daily yields on 20-year Treasury bonds for Sep. 2006 reported by the U.S. Department of the Treasury at www.treas.gov.

(e) (c) + (d).

HISTORICAL RISK PREMIUM - PROJECTED YIELD

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.1%
Utility Proxy Group Beta (b)	0.97
Utility Proxy Group Risk Premium (c)	6.9%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	5.4%
Implied Cost of Equity (e)	**12.3%**

(a) Arithmetic mean risk premium on Large Company Stocks from 1926-2005 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at Appendix C, Table C-1, p. 262.

(b) The Value Line Investment Survey (Aug 11, 2006).

(c) (a) x (b).

(d) Projected yield on 20-year Treasury bonds for 2007 based on interest rate forecasts reported by GlobalInsight, *The U.S. Economy: The 30-Year Focus* (First-Quarter 2006), Energy Information Administration, *Annual Energy Outlook 2006* (Jan. 2006), and Blue Chip Financial Forecasts (July 1, 2006).

(e) (c) + (d).

Blue Chip Forecast (July 1, 2006)

	2007				
	1Q	2Q	3Q	4Q	Avg
10-Year Treasury	5.3%	5.3%	5.3%	5.3%	**5.3%**
Corporate					
Aaa	6.3%	6.3%	6.3%	6.2%	**6.3%**
Baa	7.2%	7.2%	7.2%	7.2%	**7.2%**

Implied 2007 20 Yr. Treasury Bond Yield

10-Yr Treasuries	10-Year Sep-06	Forecast 2007	Change	20-Year Sep-06	Implied 2007
EIA	4.72%	5.19%	0.47%	4.93%	5.4%
GlobalInsight	4.72%	4.98%	0.26%	4.93%	5.2%
Blue Chip	4.72%	5.3%	0.58%	4.93%	5.5%
Average					**5.4%**

Yield Spreads

		Corporate		Utility				Spread	Spread	PU-Avg / Corp. Yield Spread		PU-BBB / Corp. Yield Spread	
		Aaa	Baa	Avg	AA	A	BBB	AA/BBB	AA/AVG	Aaa	Baa	Aaa	Baa
1	Oct	5.34%	6.29%	5.79%	5.50%	5.79%	6.08%	0.58%	0.29%	0.45%	-0.50%	0.74%	-0.21%
2	Nov	5.42%	6.39%	5.89%	5.59%	5.88%	6.19%	0.60%	0.30%	0.47%	-0.50%	0.77%	-0.20%
3	Dec	5.37%	6.32%	5.83%	5.55%	5.79%	6.14%	0.59%	0.28%	0.46%	-0.49%	0.77%	-0.18%
4	Jan	5.29%	6.24%	5.77%	5.50%	5.75%	6.06%	0.56%	0.27%	0.48%	-0.47%	0.77%	-0.18%
5	Feb	5.35%	6.27%	5.83%	5.55%	5.82%	6.11%	0.56%	0.28%	0.48%	-0.44%	0.76%	-0.16%
6	Mar	5.53%	6.41%	5.98%	5.71%	5.98%	6.26%	0.55%	0.27%	0.45%	-0.43%	0.73%	-0.15%
7	Apr	5.84%	6.68%	6.28%	6.02%	6.29%	6.54%	0.52%	0.26%	0.44%	-0.40%	0.70%	-0.14%
8	May	5.95%	6.75%	6.39%	6.16%	6.42%	6.59%	0.43%	0.23%	0.44%	-0.36%	0.64%	-0.16%
9	Jun	5.89%	6.78%	6.39%	6.16%	6.40%	6.61%	0.45%	0.23%	0.50%	-0.39%	0.72%	-0.17%
10	Jul	5.85%	6.76%	6.37%	6.13%	6.37%	6.61%	0.48%	0.24%	0.52%	-0.39%	0.76%	-0.15%
11	Aug	5.68%	6.59%	6.20%	5.97%	6.20%	6.43%	0.46%	0.23%	0.52%	-0.39%	0.75%	-0.16%
12	Sep	5.51%	6.43%	6.02%	5.81%	6.00%	6.26%	0.45%	0.21%	0.51%	-0.41%	0.75%	-0.17%
								0.52%	**0.26%**	**0.48%**	**-0.43%**	**0.74%**	**-0.17%**

Implied 2007 Utility Yields

	Average				BBB			
Blue Chip								
Based on Aaa Corporate	6.3%	+	0.48%	6.8%	6.3%	+	0.74%	7.0%
Based on Baa Corporate	7.2%	+	-0.43%	6.8%	7.2%	+	-0.17%	7.0%
GlobalInsight AA Utility	6.27%	+	0.26%	6.5%	6.27%	+	0.52%	6.8%
EIA AA Utility	6.65%	+	0.26%	6.9%	6.65%	+	0.52%	7.2%
Average				**6.7%**				**7.0%**

Treasury Bond Yield (U.S. Dept. of the Treasury)

	10-YR	20-YR
9/1/2006	4.73	4.95
9/5/2006	4.78	5.01
9/6/2006	4.80	5.02
9/7/2006	4.80	5.01
9/8/2006	4.78	4.99
9/11/2006	4.80	5.02
9/12/2006	4.78	4.98
9/13/2006	4.77	4.97
9/14/2006	4.79	4.99
9/15/2006	4.80	5.00
9/18/2006	4.81	5.01
9/19/2006	4.74	4.94
9/20/2006	4.73	4.93
9/21/2006	4.65	4.86
9/22/2006	4.60	4.82
9/25/2006	4.56	4.77
9/26/2006	4.59	4.79
9/27/2006	4.60	4.81
9/28/2006	4.63	4.84
9/29/2006	4.64	4.84
Average	4.72	4.93

COMPARABLE EARNINGS ANALYSIS

	Company	Ticker	Domicile Code	Safety Rank	Beta	Dividend Yield	Market Cap ($ Mil)	Return on Shareholders' Equity
1	ADTRAN, Inc.	ADTN	US	3	1.00	1.52	1,743.54	18.7
2	AGL Resources	ATG	US	2	0.95	3.95	2,920.47	12.9
3	Air Products & Chem.	APD	US	2	0.95	1.99	15,150.11	15.6
4	Airgas Inc.	ARG	US	3	1.00	0.73	2,962.26	13.7
5	Alexander & Baldwin	ALEX	US	3	0.95	2.19	1,971.18	11.7
6	Alliant Energy	LNT	US	3	0.90	3.02	4,481.45	12.6
7	Allstate Corp.	ALL	US	1	0.90	2.27	38,894.84	8.7
8	Amer. Financial Group	AFG	US	3	1.00	1.14	3,784.41	8.0
9	Amer. Standard	ASD	US	3	0.95	1.66	8,675.95	60.3
10	AmSouth Bancorp.	ASO	US	2	0.90	3.45	10,283.90	20.0
11	Anadarko Petroleum	APC	US	3	1.00	0.77	21,571.29	22.3
12	Apache Corp.	APA	US	3	0.95	0.89	22,101.88	24.9
13	AptarGroup	ATR	US	3	0.95	1.57	1,955.15	12.3
14	Assoc. Banc-Corp	ASBC	US	2	0.90	3.50	4,384.13	13.8
15	Astoria Financial	AF	US	2	0.95	3.20	3,031.65	17.3
16	Automatic Data Proc.	ADP	US	1	0.90	1.56	27,319.31	18.3
17	Avery Dennison	AVY	US	2	0.95	2.49	6,274.83	22.3
18	Ball Corp.	BLL	US	3	0.90	0.95	4,392.07	34.4
19	Bausch & Lomb	BOL	US	3	0.95	1.00	2,805.67	11.2
20	BB&T Corp.	BBT	US	1	0.90	3.87	23,333.46	14.9
21	BellSouth Corp.	BLS	US	2	1.00	2.61	80,434.68	11.4
22	Belo Corp. 'A'	BLC	US	3	0.95	2.94	1,753.02	8.3
23	Bemis Co.	BMS	US	1	1.00	2.23	3,567.57	12.1
24	Berkley (W.R.)	BER	US	3	0.90	0.45	6,882.33	20.7
25	Black & Decker	BDK	US	3	1.00	1.77	6,347.36	35.7
26	BOK Financial	BOKF	US	2	0.90	1.16	3,469.67	13.1
27	Brinker Int'l	EAT	US	3	0.90	1.00	3,354.09	18.1
28	Brown & Brown	BRO	US	2	0.90	0.67	4,163.48	19.7
29	Burlington Northern	BNI	US	2	0.95	1.26	28,672.49	16.1
30	C.H. Robinson	CHRW	US	2	1.00	1.21	7,478.06	26.1
31	Cabot Corp.	CBT	US	3	1.00	1.61	2,520.13	11.5
32	Cardinal Health	CAH	US	3	0.95	0.55	27,290.16	15.5
33	Caremark RX	CMX	US	3	0.90	0.79	21,679.28	11.0
34	CDW Corp.	CDWC	US	3	1.00	0.80	5,093.29	21.5
35	CenturyTel Inc.	CTL	US	3	1.00	0.62	4,711.31	9.3
36	Chesapeake Energy	CHK	US	3	0.95	0.78	12,943.24	15.4
37	Chevron Corp.	CVX	US	1	0.90	3.17	144,275.90	22.5
38	Cincinnati Financial	CINF	US	2	0.90	2.75	8,438.94	9.2
39	Citizens Communic.	CZN	US	3	1.00	6.98	4,595.40	19.2
40	Comerica Inc.	CMA	US	2	1.00	4.02	9,513.03	17.0
41	Commerce Bancorp NJ	CBH	US	3	0.95	1.37	6,499.99	12.3
42	Compass Bancshares	CBSS	US	2	0.90	2.79	7,222.47	18.0
43	ConocoPhillips	COP	US	2	0.95	2.36	100,730.20	20.3
44	Constellation Energy	CEG	US	2	1.00	2.47	10,982.55	12.1
45	Corn Products Int'l	CPO	US	3	0.90	0.95	2,424.66	7.4
46	Corporate Executive	EXBD	US	3	1.00	1.27	3,806.46	19.5
47	CSX Corp.	CSX	US	3	1.00	1.12	15,780.80	9.7
48	CVS Corp.	CVS	US	3	0.90	0.50	25,524.90	14.1
49	Dade Behring Hldgs.	DADE	US	3	0.90	0.53	3,314.95	14.4
50	Danaher Corp.	DHR	US	2	0.95	0.11	21,544.80	17.7
51	Delphi Fin'l `A'	DFG	US	3	0.95	0.78	1,998.42	11.7
52	Diebold, Inc.	DBD	US	2	0.90	2.03	2,776.23	11.8
53	Dominion Resources	D	US	2	1.00	3.47	28,098.80	9.9
54	Donaldson Co.	DCI	US	2	0.95	0.96	3,033.78	24.2
55	Donnelley (R.R) & Sons	RRD	US	2	0.90	3.11	7,295.29	13.3

COMPARABLE EARNINGS ANALYSIS

	Company	Ticker	Domicile Code	Safety Rank	Beta	Dividend Yield	Market Cap ($ Mil)	Return on Shareholders' Equity
56	Downey Fin'l	DSL	US	3	1.00	0.61	1,842.20	18.0
57	DPL Inc.	DPL	US	3	0.95	3.57	3,213.80	11.8
58	Du Pont	DD	US	1	1.00	3.29	41,480.59	25.8
59	Energy East Corp.	EAS	US	2	0.90	4.86	3,645.26	8.9
60	Expeditors Int'l	EXPD	US	3	0.90	0.92	10,259.84	21.6
61	Exxon Mobil Corp.	XOM	US	1	0.90	1.84	414,541.80	30.5
62	Fair Isaac	FIC	US	3	0.90	0.22	2,250.93	16.7
63	Family Dollar Stores	FDO	US	3	0.90	1.41	4,520.21	15.2
64	Fannie Mae	FNM	US	3	0.90	1.76	57,230.00	31.7
65	Federated Investors	FII	US	2	0.95	2.11	3,574.17	36.8
66	Fifth Third Bancorp	FITB	US	1	0.90	4.08	21,863.87	16.4
67	First Midwest Bancorp	FMBI	US	2	0.90	2.90	1,897.15	18.6
68	FirstMerit Corp.	FMER	US	3	0.95	4.92	1,889.37	13.9
69	Frontier Oil	FTO	US	3	1.00	0.40	3,328.46	61.8
70	G't Plains Energy	GXP	US	2	0.90	5.18	2,572.69	13.0
71	Gallagher (Arthur J.)	AJG	US	2	0.90	4.44	2,626.34	39.9
72	Genuine Parts	GPC	US	1	0.90	3.03	7,643.72	16.2
73	Genworth Fin'l	GNW	US	2	1.00	1.01	16,202.55	9.2
74	Graco Inc.	GGG	US	2	1.00	1.35	2,910.59	43.8
75	Harley-Davidson	HOG	US	3	0.95	1.24	17,705.03	31.1
76	Harrah's Entertain.	HET	US	3	1.00	2.16	13,689.70	8.4
77	Harris Corp.	HRS	US	3	0.90	1.01	5,766.67	18.7
78	Harte-Hanks	HHS	US	1	0.90	0.89	2,150.02	20.4
79	Hasbro, Inc.	HAS	US	3	1.00	2.06	3,836.76	13.8
80	HCC Insurance Hldgs.	HCC	US	3	0.95	1.17	3,792.11	11.4
81	Hess Corp.	HES	US	3	1.00	0.95	11,821.37	20.4
82	Holly Corp.	HOC	US	3	0.95	0.65	2,805.43	44.3
83	Huntington Bancshs.	HBAN	US	2	0.90	4.13	5,746.51	16.1
84	IDACORP, Inc.	IDA	US	3	1.00	3.01	1,704.92	6.2
85	IDEX Corp.	IEX	US	3	1.00	1.25	2,557.11	13.3
86	Illinois Tool Works	ITW	US	1	1.00	1.80	26,457.81	19.8
87	IMS Health	RX	US	2	1.00	0.45	5,436.42	73.9
88	Int'l Business Mach.	IBM	US	1	1.00	1.34	136,752.50	25.7
89	Int'l Game Tech.	IGT	US	3	0.90	1.26	13,994.19	22.9
90	KeyCorp	KEY	US	3	1.00	3.67	15,132.41	14.9
91	Kinder Morgan	KMI	US	3	0.95	3.30	14,175.84	14.1
92	Lauder (Estee)	EL	US	2	0.90	0.99	8,540.37	25.6
93	Lincoln Elec Hldgs.	LECO	US	2	0.95	1.31	2,476.03	17.4
94	Liz Claiborne	LIZ	US	1	0.90	0.55	4,226.43	15.9
95	Lowe's Cos.	LOW	US	2	1.00	0.66	46,909.00	19.3
96	Lubrizol Corp.	LZ	US	3	1.00	2.18	3,267.28	11.0
97	M&T Bank Corp.	MTB	US	1	0.95	1.97	13,541.02	13.3
98	Manulife Fin'l	MFC	US	1	0.95	2.17	51,194.88	12.9
99	Marathon Oil Corp.	MRO	US	2	1.00	1.85	31,067.36	26.1
100	Marshall & Ilsley	MI	US	1	1.00	2.25	12,200.82	15.6
101	McKesson Corp.	MCK	US	3	0.90	0.47	15,278.90	12.5
102	MDU Resources	MDU	US	1	1.00	2.29	4,242.06	14.5
103	Mentor Corp.	MNT	US	3	0.90	1.52	1,966.61	21.2
104	Mercantile Bankshares	MRBK	US	2	0.90	2.50	5,540.01	12.6
105	Microsoft Corp.	MSFT	US	1	1.00	1.41	284,654.00	31.4
106	Miller (Herman)	MLHR	US	3	0.95	0.95	2,230.50	40.5
107	Monsanto Co.	MON	US	3	1.00	0.89	24,513.30	10.1
108	Murphy Oil Corp.	MUR	US	3	1.00	1.17	9,622.26	21.0
109	National City Corp.	NCC	US	1	0.95	4.32	21,836.36	15.7
110	National Fuel Gas	NFG	US	2	0.95	3.31	3,021.62	13.2

COMPARABLE EARNINGS ANALYSIS

	Company	Ticker	Domicile Code	Safety Rank	Beta	Dividend Yield	Market Cap ($ Mil)	Return on Shareholders' Equity
111	New York Community	NYB	US	3	0.95	6.09	4,841.87	8.8
112	New York Times	NYT	US	1	0.90	3.08	3,288.09	15.4
113	Newell Rubbermaid	NWL	US	3	0.90	2.88	8,007.51	25.8
114	NIKE, Inc. 'B'	NKE	US	1	0.90	1.39	22,412.58	21.5
115	NiSource Inc.	NI	US	3	0.90	4.00	6,266.90	6.0
116	North Fork Bancorp	NFB	US	2	0.95	3.42	13,623.10	10.5
117	NOVA Chemicals	NCX	US	3	1.00	1.33	2,499.77	(8.5)
118	Occidental Petroleum	OXY	US	1	1.00	1.84	40,466.38	26.4
119	Ohio Casualty	OCAS	US	3	0.95	1.30	1,706.89	12.2
120	Omnicare, Inc.	OCR	US	3	0.95	0.20	5,460.21	9.1
121	ONEOK Inc.	OKE	US	3	1.00	3.13	4,806.65	15.4
122	Oshkosh Truck	OSK	US	3	0.90	0.77	3,822.30	19.6
123	OSI Restaurant Partners	OSI	US	2	0.95	1.57	2,463.70	13.5
124	Penney (J.C.)	JCP	US	3	1.00	0.97	16,886.53	23.3
125	PerkinElmer Inc.	PKI	US	3	0.95	1.42	2,506.86	8.4
126	PetSmart, Inc.	PETM	US	3	1.00	0.41	4,108.65	18.1
127	Pharmac. Product	PPDI	US	3	0.95	0.28	4,218.48	17.7
128	Pinnacle West Capital	PNW	US	1	1.00	4.17	4,768.93	6.5
129	Pioneer Natural Res.	PXD	US	3	0.95	0.63	5,089.51	20.6
130	Pitney Bowes	PBI	US	1	0.90	2.74	10,336.78	48.1
131	PNM Resources	PNM	US	2	1.00	3.07	1,986.50	8.2
132	Pogo Producing	PPP	US	3	1.00	0.63	2,765.91	13.8
133	Pool Corp.	POOL	US	3	0.90	1.07	2,036.47	30.6
134	PPL Corp.	PPL	US	2	1.00	3.23	12,976.86	16.5
135	Praxair Inc.	PX	US	2	1.00	1.67	19,254.44	21.1
136	Principal Fin'l Group	PFG	US	2	1.00	1.17	14,905.45	11.4
137	Progressive (Ohio)	PGR	US	2	0.90	0.14	19,131.94	22.8
138	Protective Life	PL	US	2	0.95	1.88	3,204.95	12.1
139	Public Serv. Enterprise	PEG	US	3	0.95	3.75	15,303.97	14.1
140	Questar Corp.	STR	US	3	0.95	1.12	7,192.97	21.7
141	Rayonier Inc.	RYN	US	3	1.00	4.71	3,053.61	13.7
142	Regions Financial	RF	US	1	0.95	3.68	17,280.53	9.4
143	Regis Corp.	RGS	US	3	0.90	0.42	1,748.03	13.6
144	Reinsurance Group	RGA	US	2	0.95	0.66	3,321.29	8.9
145	Reynolds & Reynolds	REY	US	3	0.95	1.11	3,128.35	23.7
146	Reynolds American	RAI	US	3	0.95	4.85	18,297.01	15.0
147	Ross Stores	ROST	US	3	0.95	0.81	4,203.55	23.9
148	Royal Dutch Shell 'A'	RDS/A	US	1	1.00	3.76	139,600.50	25.5
149	RPM Int'l	RPM	US	3	1.00	3.70	2,242.71	14.8
150	Schering-Plough	SGP	US	3	0.95	0.99	33,093.06	8.6
151	Scotts Miracle-Gro	SMG	US	2	0.95	1.08	3,032.06	9.8
152	Sherwin-Williams	SHW	US	2	1.00	1.75	7,767.17	26.8
153	Snap-on Inc.	SNA	US	2	1.00	2.40	2,685.80	10.0
154	Sonoco Products	SON	US	2	1.00	2.73	3,517.58	15.3
155	St. Joe Corp.	JOE	US	1	0.90	1.19	3,970.59	24.6
156	Stanley Works	SWK	US	3	0.95	2.33	4,177.09	19.0
157	Steelcase, Inc. 'A'	SCS	US	3	1.00	2.97	2,407.48	6.2
158	SunTrust Banks	STI	US	2	0.95	3.16	28,132.61	11.7
159	SUPERVALU INC.	SVU	US	3	0.95	2.00	6,948.90	12.3
160	TCF Financial	TCB	US	3	0.95	3.51	3,441.08	26.6
161	TD Banknorth Inc.	BNK	US	3	0.90	2.96	6,772.05	6.7
162	TJX Companies	TJX	US	2	0.95	0.96	13,093.91	33.5
163	Torchmark Corp.	TMK	US	1	1.00	0.83	6,199.63	14.1
164	Toro Co.	TTC	US	2	0.95	0.83	1,793.98	29.3
165	Total System Svcs.	TSS	US	3	1.00	1.20	4,623.90	19.2

COMPARABLE EARNINGS ANALYSIS

	Company	Ticker	Domicile Code	Safety Rank	Beta	Dividend Yield	Market Cap ($ Mil)	Return on Shareholders' Equity
166	UGI Corp.	UGI	US	2	0.90	2.82	2,634.27	18.2
167	Union Pacific	UNP	US	1	0.90	1.31	24,592.24	6.6
168	Unitrin, Inc.	UTR	US	3	1.00	4.02	2,985.57	10.0
169	UST Inc.	UST	US	3	0.90	4.08	8,989.52	-
170	V.F. Corp.	VFC	US	2	0.95	2.91	8,378.77	18.3
171	Valspar Corp.	VAL	US	3	0.90	1.64	2,722.85	13.9
172	Verizon Communic.	VZ	US	2	0.95	4.35	107,861.50	18.0
173	Washington Mutual	WM	US	2	0.95	4.91	40,777.97	12.4
174	Waste Management	WMI	US	2	0.95	2.37	20,095.40	14.3
175	Weight Watchers	WTW	US	3	0.90	1.50	4,557.57	(250.5)
176	Westar Energy	WR	US	2	0.90	4.04	2,156.02	9.4
177	Whole Foods Market	WFMI	US	3	0.95	0.93	9,134.41	12.0
178	Wilmington Trust	WL	US	1	0.95	2.82	3,071.85	17.1
179	Wyeth	WYE	US	2	0.95	1.96	71,387.11	33.0
180	Xcel Energy Inc.	XEL	US	2	0.90	4.13	8,743.87	9.1
181	XTO Energy	XTO	US	3	0.90	0.67	16,362.80	27.5
182	Zions Bancorp.	ZION	US	2	0.95	1.82	8,431.86	11.3
	Average							16.5
	Median							15.4