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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.	Docket No. E-01345A-08-0172

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Required Revenue Testimony of Ben Johnson, Ph.D. and the Direct Cost of Capital Testimony of William A. Rigsby, CRRA in the above-referenced matter.

RESPECTFULLY SUBMITTED this 19th day of December, 2008

Arizona Corporation Commission
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Chief Counsel

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ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-08-0172

DIRECT TESTIMONY

OF

BEN JOHNSON, PH.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 19, 2008

NOTE

The following testimony is a more nuanced presentation than is the norm for RUCO. I strongly encourage the reader to view the material in the order in which it is presented, and to also pay attention to the Appendix.

Stephen Ahearn
Director, RUCO

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TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. 01345A-08-0172

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Have you prepared any schedules to be filed with your testimony?

A. Yes, I have prepared Schedules BJ-1 through BJ-14. These schedules are attached to my testimony.

Q. What is your purpose in making your appearance at this hearing?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of Arizona Public Service Company's (APS) Amended Application for a base rate increase. The purpose of my testimony is to present RUCO's revenue requirement recommendation for APS in this proceeding, taking into account my analysis, as well as that of RUCO's rate of return witness Bill Rigsby.

Following this introduction, my testimony has six sections. In the first section, I briefly summarize the background of this proceeding. In the second section, I discuss APS' financial condition and APS' credit ratings. In the third section I briefly summarize and discuss APS' revenue requirement filing in general terms. In the fourth section, I discuss the rate base adjustments proposed by APS and I present RUCO's recommendations with respect to each proposed adjustment. In the fifth section, I discuss the income adjustments proposed by APS and I present RUCO's recommendations with respect to each proposed adjustment. In the sixth and final section, I summarize my conclusions and recommendations.

I have also prepared Appendix B, attached to my testimony, in which I provide some additional discussion of the attrition issue. Since RUCO does not support an adjustment for attrition, this discussion is not included in the main body of my testimony. However, the discussion in this appendix may be useful to the Commission if it decides that the Company's financial situation is weak enough to warrant additional rate relief beyond that which can be justified using a traditional test year analysis.

I. Background

Q. Can you briefly discuss APS' most recent rate case?

A. Yes. APS' current rates became effective July 1, 2007 pursuant to Decision No. 69663 issued in Docket No. E-01345A-05-0816. APS requested a revenue increase of $425,847,000, or 16.73 percent over adjusted test year revenues. [Decision No. 69663, p. 4] The Commission authorized a nominal $321.7 million increase in revenues - a 12.33% increase over test year revenues. [Id.] However, according to APS, most of that increase was related to changes in fuel recovery methods.

> While the improvements to the Company's Power Supply Adjustor ("PSA") and the new base fuel rate approved in that Decision allowed the Company recovery of its growing fuel and purchased power costs, that Decision did not compensate APS for the Company's significant increase in Operating Expenses and other non-fuel expenses. Only 0.3% of the total rate increase authorized by Decision No. 69663 was aimed at meeting APS' revenue requirement for non-fuel expenses.

Q. Can you now briefly discuss the procedural background of this case?

A. Yes. APS' initial application for a rate increase was filed with the Commission on March 24, 2008. During April, 2008, several parties filed motions to intervene. All motions to intervene were granted by Procedural Orders issued on April 25 and May 19, 2008. On June 2,2008, APS filed an Amended Application, in which it used a calendar 2007 test year, rather than one ending in September 2007. As amended, APS is seeking a gross increase in rates of $448.2 million, and a net increase of $278.2 million, as discussed below. On June 6, 2008, APS filed a Motion for Approval of Interim Rates, requesting an interim rate increase of approximately $115 million. On June 16,2008, RUCO filed an Application to Intervene. RUCO's intervention was granted on June 19, 2008.

On September 15-20, 2008 a hearing was held on APS' motion for an interim rate increase. On November 12, 2008, the Administrative Law Judge issued a recommended order denying APS' request for an interim rate increase.

II. APS Financial Situation and Credit Metrics

Q. APS claims that its credit metrics are not as strong as they need to be, and as a result, its bond ratings are barely above the "junk" category. Can you explain this concern?

A. Yes. APS states that its inability to earn its allowed rate of return "places APS's credit ratings in continued peril." [Brant Direct, p. 37] Mr. Brandt further explains:

> The unremitting earnings shortfall that results from the current regulatory model in APS's staggering growth environment has a detrimental effect on the Company's overall financial integrity and Pinnacle West's stock value, and adversely impacts APS's ability to finance the construction programs and improvements necessary to meet the demands of growth—a negative impact that will inevitably inure to the detriment of APS's customers. [Id., p. 33]

As I mentioned previously, the Company contends that it has underearned by $321 million from 2003-2007, and projects an additional shortfall of at least $380 million will occur through 2010 under present conditions.

While there is no expectation that earnings will exactly match the allowed rate of return, such a substantial level of under-earning occurring over a prolonged period is a legitimate cause for concern – particularly if it were to be sustained for several more years into the future. Mr. Brandt has testified that if the Commission does not grant adequate and timely relief, he believes "the Company's credit metrics will reach non-investment grade by the end of 2009, which could result in a credit downgrade with devastating financial results to both APS and its customers." [Id., p. 37]

Q. Can you explain how the credit rating agencies rate the Company's credit?

A. Yes. The major credit rating agencies are S&P, Moody's and Fitch. As shown below, each of the agencies has established a series of tiers designated by alphanumeric codes to rate corporate securities.

S&P	Moody's	Fitch
Investment Grade		
AAA	Aaa	AAA
AA+	Aa1	AA+
AA+	Aa2	AA
AA-	Aa3	AA-
A+	A1	A+
A+	A2	A
A-	A3	A-
BBB+	Baa1	BBB+
BBB	Baa2	BBB
BBB-	Baa3	BBB-
Speculative Grade		
BB+	Ba1	BB+
BB	Ba2	BB
BB-	Ba3	BB-
B+	B1	B+
B	B2	B
B-	B3	B-
CCC+	Caa1	CCC+
CCC	Caa2	CCC
CCC-	Caa3	CCC-
CC		CC
		C
In Default		
SD	Ca	DDD
D	C	DD
		D

Q. Where does APS currently fall within the ranges established by the credit agencies?

A. APS credit ratings are BBB-, Baa2, and BBB by S&P, Moody's and Fitch, respectively. As you can see in the table above, APS is rated on the lowest tier of "investment grade" credit by S&P, and it is rated only 1 notch higher by Moody's and Fitch., and the Company's credit metrics provide little reason to hope that this situation will improve anytime soon. The weak rating is partly due to this pattern of weak earnings, but the notable lack of success in the parent company's diversification efforts has also contributed to the weak ratings. In fact, some of the quantitative credit metrics are borderline for continuation of the existing, relatively weak, bond rating, and there is a significant risk of a further downgrade out of the investment grade category, into the high end of the the so-called "junk" category.

Q. How does APS' ratings compare to the ratings of other utilities?

A. These bond ratings fall toward the low end of the electric industry. APS states that out of a total of 139 rated utilities, "only five companies are rated lower than APS." [Brant Direct, p. 39] The ratings range from a high of AA- for Madison Gas and Elctric CO. and NSTAR Gas Co, to a low of BB- for Aquila Inc.

Q. What criteria do the agencies use to determine utility credit ratings?

A. Each agency uses numerous quantitative and qualitiative factors to determine the rating assigned to individual corporations and specific debt issuances. For example, Fitch lists the following variables:

- Corporate/Legal Structure
- Regulatory Environment
- Franchise or Concession Terms
- Price Setting (E.g., cost of service, price cap, etc..)
- Potential for Regulatory Change
- Service Area Demographics
- Energy Supply
- Commodity Price Exposure
- Operating Efficiency
- Management and Strategy
- Financial Resources
- Capital Structure and Financial Flexibility
- Financial Ratio Analysis
- Liquidity
- Risk Asessment and Guideline Credit Ratios [Attachment DEB-4]

Q. Has S&P provided any explanation of its rating for APS?

A. Yes. S&P lists the following "major rating factors":

Strengths:

- A favorable power supply adjuster (PSA) that while capped at 4 mils per EBB-/Stable/A-3 kilowatt-hour (kwh) is benched to projected power prices, which should minimize fuel and purchased power deferral balances going forward;
- Declining legacy deferral balances, reflecting the recovery through surcharges of past fuel and purchased power costs from retail ratepayers;
- An attractive service territory, which while currently weakened by a real estate cycle that is depressing new customer connections, nevertheless is expected to experience above- average growth over the long run;
- A balanced power supply portfolio that is a mixture of coal, nuclear, and gas generation and purchases; due to a self-build moratorium in place until 2015, Arizona Public Service (APS) is expected to increasingly rely on gas-fired purchases, which underlines the importance of a strong PSA;
- Stabilized operations at Palo Verde, although the nuclear units remain under heightened Nuclear Regulatory Commission (NRC) scrutiny; APS

operates the plant and owns a 29.1% share of the plant; and

- A manageable maturity schedule for both the parent and the utility until 2011 when about $578 million is due on a consolidated basis.

Weaknesses:

- The consolidated financial profile of the company is unlikely to meaningfully improve for the foreseeable future due to APS' heavy capital investment, coupled with a lagged regulatory process in Arizona;
- Continued tension in the relationship between APS and the Arizona Corporation Commission (ACC), which is particularly unfavorable for credit quality due to the company's ongoing need for rate relief;
- APS' re-filing of its 2008 general rate case based on a revised test year is expected to delay rate relief past the summer of 2009, which will, all else equal, weaken cash flow measures;
- Consolidated free operating cash flows are expected to be negative through at least 2010, based on the company's capital spending program; and SunCor's near-term prospects to make distributions to its parent are limited, due a depressed real estate cycle, which has hit the southwest especially hard. [S&P Ratings Direct, June 25, 2008; APS13072]

The S&P further states:

> We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the outcome of the company's current case. [S&P Ratings Direct, June 25, 2008; APS13070, pp. 2-3]

Q. Has Moody's provided any explanation of its rating for APS?

A. Yes. Moody's provides the following "ratings rationale":

> The Baa2 rating for the senior unsecured obligations of

> APS reflects the stability of its regulated cash flows, the economic strength of its service territory, its regulatory environment, cash flow credit metrics that are appropriate for the rating, and its position as a subsidiary of Pinnacle. The rating and outlook consider the traditionally challenging regulatory environment in Arizona, but also contemplates recent ACC decisions and regulatory activities that appear intended to reduce regulatory lag and provide more timely recovery of certain costs.
>
> Given APS' current significant capital expenditure program, the company will require continued, timely regulatory support to maintain credit metrics that are appropriate for its rating. The stable outlook assumes APS will be reasonably successful in managing its regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that APS will maintain a balanced approach with regards to financing its capital expenditures with a goal of maintaining or improving its current level of financial strength. [Global Credit Research Credit Opinion, July 28, 2008; APS13051]

On July 25, 2008, Moody's upgraded APS' outlook to "stable", providing the following explanation:

> The stable outlook considers the companies' improving regulatory environment and operating performance with financial results that are expected to remain consistently within the range expected for integrated utilities rated Baa. APS has begun to receive more supportive regulatory decisions, including "new connection" fees allowing faster recovery for new hookups plus a transmission cost adjustor and power supply adjustor which has limited APS' exposure to fuel and purchased power fluctuations. In addition, performance at the Palo Verde nuclear power plant has improved and APS is making progress in identifying and improving the safety and communication issues at the plant. [Global Credit Research Rating Action, July 25, 2008; APS13050]

Q. What explanation has Fitch provided for its APS rating?

A. Fitch provides the following information:

> The ratings of Arizona Public Service Company (APS) are supported by the June 2007 Arizona Corporation Commission (ACC) order in APS's general rate case (GRC), which increased revenue $322 million and improved its power supply adjustor.
>
> Fitch estimates funds from operations to interest expense will approximate 4.6 times (x) in 2007 and 4.3x in 2008, consistent with low 'BBB' credit metrics.
>
> Regulatory lag, combined with APS's large capital expenditure program, is expected to result in lower operating profit, cash flow and credit metrics in 2008, with anticipated stabilization and modest improvement in 2009–2010, in Fitch's opinion.
>
> The Palo Verde Nuclear Generating Station's operating record has improved under new management in 2007. [Fitch Ratings, January 23, 2008; APS13044]

Q. To what extent do the agencies look at Pinnacle West and APS' corporate structure when issuing ratings?

A. That is certainly one of the factors they consider. For example, Fitch states:

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

> capital may be damaged by the financial difficulties of a parent or affiliate and/or whether the utility is dependent on the parent for equity to support capital expenditures. The analysis also considers whether the corporate parent relies on utility dividends to support other regulated or unregulated subsidiary operations. In cases that Fitch determines there is a significant business with financial or legal interdependence, the rating differential between a utility and its parent or a utility and its subsidiary is likely to be limited. If financing occurs at the parent for all entities, or where significant cross-subsidies between the utility and its affiliates occurs, a consolidated rating is likely. [Attachment DEB-4, p. 13]

Similarly, the S&P states:

> The nature of the owner— e.g., government, family, holding company, or strategically linked business can hold significant implications for both business and financial aspects of the rated entity. Ownership by stronger or weaker parent companies can substantially affect the credit quality of the rated entity. ... We never rate corporate entities on a standalone basis. [Corporate Ratings Criteria, 2008, p. 34]

Q. Do credit agencies focus exclusively on credit metrics or financial risks?

A. No. The rating agencies generally look beyond "financial risk" to also consider a wide range of variables which can be broadly classified as being related to "business risk". As explained by S&P:

> Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow. ... [R]atings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics

> are rated very differently, to the extent that their business challenges and prospects differ. [Corporate Ratings Criteria, 2008, p. 20]

For U.S. utilities, S&P publishes the following business risk/financial risk matrix:

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

Source: Attachement DEB-4, p. 12

As the matrix format makes clear, the interaction of business and financial risk, together with actual financial performance (credit metrics) strongly influence the outcome of the ratings process. In general, because regulated public utilities tend to have excellent or strong business risk profiles, it is feasible to achieve relatively high credit ratings, even if they issue substantial amounts of debt, and thus incur a moderately high degree of financial risk. As S&P explains, the business risk profile "loosely determines the level of financial risk appropriate for any given rating." [Attachment DEB-4, p. 12]

S&P explains that regulated utilities and holding companies that are "utility-focused" virtually always fall in the upper range ("Excellent" or

"Strong") of business risk profiles. [Id.]

> The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile-underpin the business risk profiles of the electric, gas, and water utilities. [Id.]

Consistent with this general pattern, S&P considers APS' business risk profile to be "strong".

> The company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges. [S&P Ratings Direct, June 25, 2008; APS13072]

Q. How does S&P evaluate financial risk?

A. The S&P rating agency analyzes financial risk both qualitatively and quantitatively, "mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP." [Attachment DEB-4, p. 12] S&P provides the following indicative financial risk ratios for U.S. utilities:

	Cash Flow		Debt Leverage
	FFO/Debt (%)	**FFO/Interest (x)**	**Total Debt/Capital (%)**
Modest	40-60	4.0-6.0	25-40
Intermediate	25-45	3.0-4.5	35-50
Aggressive	10-30	2.0-3.5	45-60
Highly Leveraged	Below 15	2.5 or less	Over 50

Source: Attachment DEB-4, p. 12

Q. Where does APS fall on this matrix?

A. According to S&P's June 25, 2008 report, APS' "Funds From Operations" (FFO)/Debt ratio is 16%, FFO/Interest ratio is 4x, and debt to total capital is 57% [S&P Ratings Direct, June 25, 2008; APS13070, p. 2] The debt to capital ratio computed by S&P is significantly worse than the analogous debt ratio which was approved by the Commission in the last rate case.

This 57% debt ratio places APS near the unfavorable end of the range for the "Aggressive" financial risk category. Similarly, the FFO/Debt ratio places APS in the middle of the range for the "Aggressive" financial risk category. The FFO/Interest data is much more favorable – APS falls toward the favorable end of the range for the "Intermediate" category, and APS nearly qualifies for the "Modest" financial risk category. With two out of the three indicators being consistent with the "Aggressive" financial risk category, and given a "Strong" business risk profile, the S&P rating of BBB- is consistent with S&P's stated criteria.

Q. Are these ratios all that the agencies consider when rating utilities?

A. No. The agencies review many quantitaive and qualitative factors, including a variety of other financial ratios, not included in this simplified matrix. This is an important factor to keep in mind, since not all ratings align perfectly with this sort of simplified matrix. For example, S&P states:

> The use of the FFO metric for some regulated utilities, for instance, can be misleading as it does not capture the variation in regulatory assets or liabilities. [Corporate Ratings Criteria, 2008, p. 41]

Q. Should the Commission be concerned about APS' bond rating and credit metrics?

A. Yes, this is a legitimate concern, particularly since the APS ratings are currently toward the low end of the industry range, and since any substantial further degradation could put the Company below the "investment grade" categories. The most obvious reason for concern is the impact of any further downgrading on the interest rates which would be paid by the Company when it needs to raise additional debt capital. As ratings decrease, the required interest on new issuances increases. These increased debt costs lead to higher costs for customers over the life cycle of the debt issuance (typically 20 years).

However, a simple cost-benefit analysis focused exclusively on measurable differences in interest rates is not sufficient to fully understand the adverse impact of a further deterioration of the Company's credit ratings, particularly if all three of the rating agencies were to drop the Company's debt into the "junk" category. If such an across-the-board deterioration were to occur, it could impose substantial costs on the Company's customers and potentially on the entire state of Arizona.

Q. Can you elaborate on the potential adverse impact of an APS downgrade?

A. To fully understand the potential problems, it is helpful to review a few basic facts. First, the market for newly issued junk-rated debt is limited. While there are many junk bonds on the market, many of these were originally issued with higher ratings, and were subsequently downgraded when problems were subsequently encountered by the issuer. While it is possible to issue new debt with a low bond rating, provided the issuer is willing to pay a high enough interest rate, in practice the market for such debt is relatively thin and uncertain, and the cost could actually exceed the cost of equity. In this regard, it is important to note that issuance of additional debt bearing a high interest rate will weaken the firm's credit metrics, particularly its FFO to interest ratio, increasing the firm's financial risk, and potentialy leading to a further bond downgrading.

As well, if APS were to assume the burden of paying inordinately high interest rates on newly issued debt, it would further reduce the amount of protection offered to its existing creditors, thereby increasing the risk of default or bankruptcy. In turn, this would increase the risk facing stockholders, which would lead to an increase in the cost of equity, making it more difficult to tap the equity markets, and result in a higher allowed return on fair value. Simply stated, a substantial further downgrading could lead to a series of undesirable ripple effects that are difficult to predict in advance, but are not in the best interests of either shareholders or customers, and which should certainly be of concern to the Commission.

Moreover, it is important to remember that the public utility industry has historically been perceived as a safe haven for both stock and equity investors. Consistent with that general perception, the vast majority of all major publicly held utilities have maintained investment-grade bond ratings for many decades. Thus, to have a major utility like APS drop into the junk bond category – particularly if this change were confirmed by all three major rating agencies – would be an unusual event that would be rather newsworthy.

If the rating change were not the result of some unique, well understood and rarely encountered risk, like the shuttering of a nuclear plant due to safety violations, it could have a shock effect on investor attitudes toward other utilities operating in the state, or even for the state as a whole. Even if the downgrading were attributable to a highly visible, easily understood problem, investors, banks, Wall Street analysts and others may not give APS, or the state, much benefit of the doubt. Instead, they may perceive the decline into junk bond territory as a warning that other, more systemic risks or problems may exist with the state's economy, or its regulatory climate.

Even if these perceptions were not valid, the resulting cost of a downgrading could be more substantial than the nominal cost which would be estimated if one only focused on the increased interest payments on future debt issuances by APS. A substantial downgrading could generally poison investor attitudes, leading to increased debt and equity costs for the other utilities in the state – higher costs which would ultimately be passed through to their customers.

Q. Are there aspects of the financial "crisis" which began in September 2008 which ought to be considered in evaluating the potential impact of an APS downgrade?

A. Yes. We have recently seen extreme swings in credit markets, triggered by relatively minor changes in the underlying facts. Once perceptions of the credit-worthiness of major institutions like Lehman Brothers or Wachovia turned a bit negative, the shift in perceptions began to feed on itself, leading to rapidly escalating atmosphere of fear and uncertainty, which in turn had very real consequences for these firms and others.

During a financial crisis or tight credit environment, even firms with an investment grade bond rating may find it more difficult than normal to issue additional debt or equity. Having a bond rating toward the low end of the utility industry, the Company may find it difficult to fully fund its planned capital construction program – bearing in mind that merely offering to pay higher than normal interest rates wouldn't necessarily solve the problem, since the very need to offer such high rates could be perceived as a sign of weakness, pushing away more risk-averse investors and making it harder to raise capital in the future (since the FFO/interest ratio will deteriorate as higher interest rates are paid on new issuances).

Absent the ability to access the debt market on a routine basis at attractive interest rates, APS would be left with relatively limited and unattractive options. It could stop paying dividends (which would effectively force Pinnacle West to do the same thing), and attempt to meet its financing needs entirely through internally generated cash flow. APS could slow, or halt, all but the most urgently needed construction projects, but if this were to continue for very long, it could result in a reduction in service reliability, or require extraordinary measures to maintain reliability, such as rolling brownouts during peak hours, or a temporary moratorium on new service connections in order to constrain demand to fit within the capabilities of the system.

To some degree, a crisis environment, and the potential for reduced reliability, brownouts, or similar measures, may provide a degree of self-correction, discouraging people from moving into the state, thereby limiting growth and helping to maintain reliability despite a limited ability to finance construction. The Company could also request some sort of emergency rate relief – perhaps a temporary emergency surcharge which forces customers to contribute funds for the construction of needed facilities. While this could prevent blackouts or brownouts, it isn't an ideal solution, since it would force current customers to pay for facilities that will benefit future customers over the next several decades.

Needless to say, even enumerating this list of potential "solutions" to a loss of routine access to credit markets is sufficient to suggest that it would be highly desirable to avoid these scenarios. If APS were to lose access to credit markets on reasonable terms, even if that loss only occurs for only a relatively short period of time, (e.g. until the Commission steps in with emergency rate relief), the adverse economic impact could be substantial.

Finally, it is worth noting that an across-the-board decline into junk bond territory by one of the state's largest utilities would be a journey into unfamiliar territory. Conceivably, there might be serious adverse consequences for the state's economy as a whole. As many have observed in various other contexts, a good reputation takes years to acquire, but it can be destroyed overnight, as the result of a single sufficiently notorious incident or mistake.

The impact of an APS bond downgrading is hard to predict, since it will depend partly on the circumstances at the time, and partly on the way those circumstances are perceived. But, it is important to realize this is not a risk that should be taken lightly. A downgrading could have a long lasting negative impact on attitudes on Wall Street, and in the board rooms of national and multi-national corporations that do business in the state, or might contemplate operating in the state in the future. Particularly if credit difficulties lead to uncertainties about the future reliability of the state's power system, it could adversely affect the state's reputation with regard to its overall business climate.

While the cost of power is certainly an important consideration for firms that are evaluating where to operate or where to expand their operations, the fear of not having enough power available when needed could be an even more important consideration. The differences in cost per KWH seen in different states, or attributable to different bond ratings, could seem relatively trivial when compared to the risk that a new warehouse or office building won't be allowed to hook into the electrical grid, or the risk of rolling brownouts or blackouts if adequate construction financing weren't available to meet the state's growing power needs.

Were the reliability and stability of the state's power grid ever called into question, even if the actual risks were relatively remote, it could lead to a crisis in confidence that is reminiscent of the ones recently experienced in the credit markets, where investors over-react to bad news, discouraging them from investing in the state, which in turn leads to adverse consequences which greatly outweigh the relatively modest cost of preventing the problem before it arises.

Accordingly, regardless of what specific decisions it adopts with respect to particular issues in this case, the Commission should be sensitive to investor perceptions, and it should strive to provide assurance in its order that it understands the importance of ensuring that APS retains access to capital markets on reasonable terms. As well, it should make an effort to clearly communicate its intention to continue to treat APS shareholders and bondholders fairly.

Furthermore, when weighing the merits of alternative regulatory policies in this proceeding, the Commission should not only consider the readily measurable differences in rates per KWH which would result from those policies, but it should also give appropriate consideration to the indirect, long term impacts of the various policy options, including the benefits of taking innovative steps to help ensure that APS can maintain an adequate bond rating. Where reasonable policy options exist that would ameliorate the alleged attrition problem, and provide reason for the rating agencies to maintain or increase APS's bond ratings, without undermining core principles of regulation or placing an unfair burden on ratepayers, those options should be given serious consideration – even if they deviate from the Commission's long standing practice.

Q. You've painted a rather bleak picture of the potential consequences if an across-the-board bond downgrading were to occur. Are you suggesting that these risks should dominate the Commission's analysis of the issues in this case?

A. No, not at all. But I wanted to make clear that RUCO recognizes the importance of maintaining a reasonable bond rating, notwithstanding various differences of opinion that may exist concerning the most appropriate resolution of various specific issues. As well, the Commission should realize that the concern about credit metrics are a key consideration in this case – one that the Commission should carefully weigh, and which might justify taking action in certain instances that deviates from its normal practice. The Commission should carefully evaluate the credit rating and attrition issues, rather than relying entirely on the Commission's past practice, or merely applying an ad hoc extension of its past practice, in an indirect attempt to ensure that the Company gets adequate support for its credit metrics.

That said, I am not by any stretch of the imagination suggesting that the Commission should throw all other concerns overboard or to accept every one of the Company's requests in this case, no matter how excessive or unreasonable, in a misplaced effort to minimize the risk of a downgrading. For example, one reason why APS' credit metrics have been weak in recent years is that management incurred costs that were found to be imprudent. I believe a vigilant regulatory regime, which forces stockholders to absorb imprudent costs encourages greater efficiency and is ultimately in everyone's best interest. However, in the short run these imprudent decisions, and the consequent regulatory disallowances are hurting the Company's cash flow and other credit metrics, and this may be one of the reasons the rating agencies perceive a higher level of business risk compared with states which does not have the resources, or inclination, to identify and disallow imprudent costs.

Arizona has constitutional requirements that require fairness to both consumers and stockholders. As a result, it is certainly possible that the regulatory system may be somewhat less favorable to investors than one that is solely the creation of a legislature that is subjected to intense lobbying by the industries that are regulated. But, this is something the Commission should treat as a given. For regulation to work as intended, management of monopolies cannot be given a blanket promise of immediate, full recovery of all costs regardless of how imprudent or unreasonable those costs might be, and regardless of whether those costs are actually being incurred, or merely anticipated in the future.

In competitive markets, firms are rewarded for unusually good decisions, and they are forced to absorb the cost of unusually poor decisions. Similarly, it isn't economically efficient or fair to require customers to reimburse imprudently incurred costs, merely because of the potential effect of a disallowance on the Company's credit metrics.

Similarly, it isn't cost effective or logical to strive for an extremely high bond rating. It might be feasible for APS to achieve a AA bond rating by maintaining a 95% equity ratio, but this clearly would not be cost effective, particularly given federal income tax policies which treat interest payments as deductable, but dividends are paid with after-tax dollars.

It is also worth noting that the Company's current, relatively weak, bond rating is not primarily traceable to regulatory lag or attrition. In addition to problems with imprudent costs, there are other factors that have contributed to the current situation. For example, if management had relied less on debt financing and contractual arrangements that have some of the same credit characteristics as long term debt, and instead had made larger, more frequent equity infusions into APS, its credit metrics would be stronger, possibly justifying a higher rating.

Similarly, despite management's best intentions in establishing a holding company structure and attempting to diversify away from the electric utility business, it was almost inevitable that such an effort would ultimately worsen the Company's business risk profile. There are very few fields of endeavor with more favorable business risk characteristics than the electric utility industry, and thus virtually any diversification effort will tend to introduce additional elements of business risk. This has certainly been the case with PNW's diversification efforts to date, which have been focused in areas which are potentially quite risky and cyclical – real estate development and energy services. The result of these efforts has been to worsen the business risk profile for PNW, and thus indirectly make it more difficult for APS to maintain or improve its bond rating. Further exacerbating the inherent problem of introducing more risk into its business risk profile, PNW's diversification efforts have not been particularly successful. As a result, it appears that the diversification effort has generally yielded weaker, more volatile earnings, lower interest coverage, and general downward pressure on PNW's credit metrics.

When discussing its consolidated credit ratings for Pinnacle West and APS, S&P states:

> APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. [Pinnacle West Ratings Report, June 25, 2008; APS13073, p. 2]

S&P also noted that Pinnacle West and APS's categorization as having an "agressive" financial risk profile was due in part to "the presence of unregulated activities, which can be unpredictable in their earnings contributions." [Id.] This view is supported by the operating results of Pinnace West's unregulated subsidiaries. SunCor, Pinnacle West's real estate subsidiary, experienced a 61% reduction in net income from 2006 to 2007 ($61 million vs. $24 million). [Pinnacle West/APS 2007 10K, p. 20] Further, Pinnacle West's other unregulated subsidiairies have all experienced net operating losses the past 3 years.[1] [Id., pp. 20-21]

1 Pinnacle West Marketing and Trading only began operating in 2007. It had a net loss of $11 million in its first year of operations.

III. APS' Filing: An Overview

Q. Can you now summarize APS' overall revenue request?

A. Yes. APS requests a $264.3 million increase in non-fuel base rates. [Amended Application, p. 3] The requested increase is based on in part on adjusted test year sales and expenses during the 2007 test year. However, it also reflects numerous post-test year adjustments, as well as an explicit "attrition" adjustment of $79.3 million. [Id., p. 4]

APS is also requesting a $183.9 million increase in its fuel related base rates. [Id., p. 3] $170 million of this amount would be recovered by the existing PSA absent Commission action in this case, and thus the net impact of the fuel related portion of its request is to increase customer rates by $13.9 million. Hence, adding the non-fuel base rate increase and the net effect of the fuel related rate changes, if APS is granted all of the relief it is requesting, customers will pay approximately $278.2 million more per year. [Brandt Direct, p. 14]

Q. Has APS proposed various adjustments to its actual test year results?

A. Yes. APS has proposed several adjustments to its test year rate base. On an ACC jurisdictional basis, these adjustments collectively result in a $418 million increase in the rate base. [Schedule B-1] Similarly, APS has proposed numerous adjustments to the actual test year operating income.

On an ACC jurisdictional basis, these adjustments collectively result in a $181 million net reduction to its operating income below the actual level experienced during the test year. [Schedule C-1, p. 2] Multiplying this cumulative adjustment amount by APS' Gross Revenue Conversion Factor of 1.6491 suggests that approximately $298 million of the requested revenue requirement is attributable to the net effect of these adjustments, rather than to the actual, unadjusted test year results.

Further analysis suggests that without its proposed adjustments to annualize cost increases that occurred after the test year, the Company's filing would show very little need for any rate relief. Stated another way, the actual historical test year provides very little justification for a rate increase – nearly the entire amount of the Company's proposed rate increase is based on its claims concerning attrition and cost increases occurring after the end of the test year.

Q. Can you explain the concept of pro forma adjustments, in general terms?

A. Yes. Although terminology can vary, test year adjustments can be classified into various groups, based on the underlying purpose or theoretical basis for making the adjustment. Company witness La Benz speaks of three major types: normalizations, annualizations and out-of-period adjustments. He describes normalizing adjustments as follows:

> Normalization adjustments compensate or adjust for unusual levels of operations experienced during the Test Year period. These adjustments generally relate to items

> that are abnormal in amount or nonrecurring in nature and are made to better reflect what is believed to be an ongoing level of operations. [La Benz Direct, p. 15]

Mr. La Benz describes out of period adjustments as follows:

> Out-of-period adjustments remove expenses or revenues properly recorded during the Test Year, but which are associated with operations from another year. [Id., p. 16]

He describes annualizing adjustments as follows:

> Annualization adjustments recognize that some events occurring during the test period are ongoing and must be adjusted to reflect their impact over an entire twelve-month period. One example of an annualization is for the payroll increases that happen during the Test Year. Since payroll costs will be higher on an ongoing basis than what was recorded during the Test Year, an adjustment must be made to reflect the prospective level of costs. [Id., pp. 15-16]

Many of the adjustments in the "annualizing" group are designed to update costs beyond the test year, or to reflect the added costs associated with additional investment and inflation which didn't occur until late in the test year, or which are anticipated to occur after the test year. These adjustments are a crude attempt to compensate for the alleged attrition problem – they attempt to capture the effect of inflationary cost increases which weren't fully reflected during the test year, but occurred near the end of the test year, or after the test year.

While the concept of adjusting for "known and measurable" cost increases is a potential method for dealing with inflation and attrition, this approach tends to be arbitrary, and controversial, particularly with respect to determining the appropriate cut-off date for the various adjustments, and the degree to which internal consistency or "matching" can be achieved – or even attempted.

RUCO believes the Commission should continue to use an historical test year, and it should reject the Company's proposal to make a long series of ad hoc adjustments stretching far beyond the test year. If the Commission is persuaded that the Company's financial situation warrants extraordinary measures that go beyond its traditional historical test year approach, I don't believe the best solution is to accept more and more adjustments for "known and measurable" changes, or to extend the cut off date for cost increases farther and farther beyond the end of the test year while leaving revenues frozen at the level which occurred during, or at the end of, the test year.

While it has long been accepted by this Commission and many other regulators, trying to solve a potential problem with attrition by adopting adjustments for "known and measurable" changes to the historic test year is an inherently difficult and controversial process. Should the Commission only consider changes which occurred during the test year? Or, should the Commission go a few weeks, or months or even a couple of years beyond the test year? In the Company's filing, it proposes a mish-mash of different adjustments, calculated as of different dates. No overarching principle has been put forward to justify the particular mix of adjustments and calculation dates, and the end result deviates greatly from the Company's actual operating experience during the test year. There is no assurance that the end result of this series of inconsistent adjustments is reasonable, or representative of actual conditions that can reasonably be anticipated in the future.

While I will readily concede that at first blush it seems reasonable to extend the cut-off date for known and measurable adjustments to go as far as possible past the end of the test year, this is not a good solution to an attrition problem, where one exists. Extending adjustments farther and farther beyond the test year tends to degenerate into an arbitrary, ad hoc, and ultimately unsound process of picking and choosing items to be included in the adjustment process, as well as picking and choosing the dates to be used in developing each of the adjustments. There is no sound theoretical basis for deciding exactly how far to go beyond the test year, yet it is clear that the farther one goes past the test year, the less the Commission will be relying on actual experience, and the more it will be relying on a hypothetical version of what might possibly occur in the future.

The Company has proposed an ad hoc mixture of adjustments with no consistency to the dates used for the various adjustments, and no consistency in determining the scope of each adjustment. For instance, it proposes to annualize revenues to reflect the number of customers present at the end of the test year, but it proposes to annualize non-union payroll costs as of March 2008, and it proposes to annualize union payroll costs as of March 2009. Similarly, it has proposed a variety of different rate base adjustments, for plant additions that occurred, or were expected to occur, as of many different dates during 2008 and 2009. Yet, even with this cherry picking of adjustments and dates, the Company's indicates that it has no faith that it's proposals will adequately compensate for the alleged attrition problem, and thus it has also proposed an additional, explicit attrition adjustment.

By limiting the adjustment process to only consider revenue increases through December 2007, while including a wide range of cost increases stretching through mid-2009, the Company is proposing a severe mis-match of revenues and costs with no assurance that the final end result of this mis-matching process is in any way reasonable or an accurate method for compensating for the alleged attrition problem.

Rather than debating the merits of each of these adjustments in isolation, one-by-one, or attempting to put forward a different ad hoc mixture of adjustments, my general approach has been to start with a specific cut-off date, and then to remove all of the attrition-related adjustments that are inconsistent with that cut-off date. To the extent the Commission is convinced that the Company's financial situation merits providing compensation for attrition, I believe it would be preferable to replace all of these ad hoc adjustments with a comprehensive, balanced response to the attrition problem, as described in the appendix to my testimony.

For purposes of this testimony, I have assumed a December 31, 2007 cut off date. I realize that the Commission may be unwilling to provide an comprehensive, explicit form of attrition compensation, yet be persuaded that some deviation from that strict cut off may be warranted in this case, given the concerns I addressed earlier with respect to APS' credit metrics and bond ratings. Thus, I realize the Commission might conclude that some deviation from a strict historical test year is warranted – e.g. by accepting some of the adjustments related to the first 6 or 9 months beyond the test year. However, before pursuing that sort of ad hoc solution, I would recommend the Commission at least consider a more comprehensive, explicit approach to dealing with the alleged attrition problem.

Accordingly, I have provided an appendix to my testimony, in which I discuss the attrition issue in more depth, and I describe an alternative approach to attrition compensation, which is not based on a series of arbitrary adjustments to the historical test year.

Q. What cut-off date are you recommending for dealing with the attrition-related pro forma adjustments?

A. I recommend the Commission use a cut off date of December 31, 2007 (the end of the test year). This provides compensation for roughly 6 additional months of inflationary cost increases, from the mid-point of the test year to the end of the test year, and it provides a specific, readily identifiable cut off point for for the Company's revenue requirements. While RUCO is not recommending any other attrition compensation, to the extent the Commission concludes that additional compensation is warranted by the unique circumstances of this case, particularly the weak status of APS's credit metrics, a reasonable approach to calculating that compensation is set forth in the appendix to my testimony.

IV. Rate Base Adjustments

Q. Can you briefly describe the Company's proposed rate base adjustment 1 - the Palo Verde Unit 3 Steam Generator?

A. Yes. The Palo Verde steam generators have been damaged by heat and corrosion. [Kearns Direct, p. 24]

> The Palo Verde owners, including APS, have determined it is both necessary and economically desirable to replace the Palo Verde steam generators and related equipment in each Unit to preserve the Unit's output and to improve the plant's reliability. ... The Unit 3 steam generators are the final set of steam generators being replaced at Palo Verde, and the Company seeks to recover those costs in this proceeding. [Id.]

In addition to two steam generators, "three low-pressure turbine rotors, core protection calculators and pressurized heaters are being replaced." [Id., p. 25] The new generator and related equipment was placed in service on January 19, 2008. [Id., p. 24] The Palo Verde steam generator adjustments include a $48.265 million addition to gross utility plant, and a $43.934 reduction in accumulated depreciation, for a $92.199 million increase in rate base. [SFR Schedule B-2]

Q. Did APS request a similar adjustment in its last rate case?

A. Yes. APS requested an adjustment for the replacement of the steam generator on Palo Verde Unit 1. However, that unit was replaced during the 2005 test year. In this case, the Unit 3 steam generator was replaced a few weeks after the end of the 2007 test year.

Q. What is your conclusion with regard to the Unit 3 steam generator?

A. I recommend excluding these adjustments because they occurred after the test year. It is also worth noting that analogous cost increases for other portions of the Palo Verde plant occurred in earlier portions of the historical period which I studied in developing my recommendations concerning attrition. Thus, I believe this particular cost increase – though it occurred just shortly after the end of the test year, is not so unique as to justify making an exception to the general cut-off date of December 31, 2007.

Q. Can you now discuss the Company's rate base adjustment 2 - the Cholla Generating Station Environmental Projects?

A. Yes. APS recently initiated several environmental projects at the Cholla Generating Station. The projects include a lime slaking upgrade, slurry disposal, and replacement of coal burners with burners that reduce the production of nitrous oxide. [Kearns Direct, pp. 26-27] These projects were placed in service in May of 2008. [Id., p. 26] The Cholla Environmental Projects adjustments include a $14.944 million addition to gross utility plant, and a $664,000 reduction in accumulated depreciation, for a $15.608 million increase in rate base. [SFR Schedule B-2] The increase in rate base was calculated "using the new equipment's estimated cost as of the date on which the equipment was placed into service." [Kearns Direct, p. 27]

Q. Did APS request a similar adjustment in its last rate case?

A. In the previous rate case, APS requested an "Environmental Improvement Charge" of $0.00016 per kWh to be collected from most customers, to be used to pay for future environmental projects. [Decision 69663, pp. 82-83] The Commission refused to adopt the proposed adjustor, noting that it would include forecasted costs. [Id., p. 86] Instead, the Commission authorized APS to collect a $0.00016 per kWh surcharge from most standard offer customers, to be known as the "Environmental Improvement Surcharge" (EIS). The Commission required APS to deposit money collected by the EIS in a separate interest-bearing account, and authorized APS to draw from the account to fund environmental improvements. [Id., p. 86] APS was instructed to consider the balance in the EIS account a regulatory liability, and amounts withdrawn were required to be considered Contributions in Aid of Construction. [Id.]

Q. What is your conclusion with regard to the Cholla Generating Station Environmental Projects?

A. I recommend the Commission not adopt this adjustment, for the reasons I discussed above. The plant improvements were not placed into service until roughly 5 months after the test year. Instead of picking and choosing an ad hoc series of adjustments for specific cost increases, while ignoring offsetting cost decreases and revenue increases which occurred during the same time period, I believe it would be preferable to adopt a uniform, consistent cut-off date as of the end of the test year. To the extent the Commission concludes that further action is warranted to deal with the attrition problem, I believe it should consider doing this through a separate, comprehensive response, as described in the appendix to my testimony.

Q. Can you now discuss the Company's proposed rate base adjustment 3 - Yucca Units 5 and 6?

A. Yes. APS recently built new peaking facilities at the Yucca Power Plant in Yuma, Arizona. The "Yuma Assets" consist of two 48 MW natural gas-fired, simple cycle, peaking electric generating units. [Dinkel Direct, p. 4] At the time APS' testimony was written, the Company expected the units to be placed in service during the summer of 2008. [Kearns Direct, p. 27] APS would like to include the units in rate base, and seeks a declartion that its decision to "direct build" the units was prudent. According to witness Dinkel, the Company determined that building the units itself would cost $4.6 million less it would incur if it relied on a developer. [Dinkel Direct, p. 7] The Yucca Units 5 and 6 adjustment consists of a $75.758 million addition to rate base. [SFR Schedule B-2] The addition to rate base was calculated "using the estimated cost of construction for the two units as of the time when the equipment is expected to be placed into service." [Kearns Direct, p. 28]

Q. What is your conclusion with regard to the Yucca Units 5 and 6 adjustment?

A. I recommend the Commission reject this adjustment. These new units were not placed into service until well after the test year, and I don't believe the alleged attrition problem can best be resolved by picking and choosing an ad hoc series of adjustments for specific cost increases, while ignoring offsetting cost decreases and revenue increases which occurred during the same time period. Given the importance of the attrition issue in this case, I believe it is preferable to adopt a uniform, consistent cut-off date as of the end of the test year, and to analyze the alleged attrition problem in a comprehensive manner, rather than debating the merits of a series of ad hoc responses to portions of the overall problem.

In this regard, I would note that the exact cost and completion date of these units was not known when the Company prepared its testimony, and that the filed adjustments are based on estimates which are undoubtedly less than perfect. Similarly, it is impossible to know precisely how much impact the new Yucca units will have on the Company's operating costs until experience is gained with them under actual operating conditions. Presumably, however, these are not simply a dead-weight burden on the Company. There may be some cost savings, if the new units allow the Company to produce electricity at a lower cost per kwh during certain times, by displacing other peaking unites with higher unit costs, or by reducing the need to purchase power from other suppliers. As well, as new generating plants and other facilities are added to the system it becomes feasible to serve load growth, which allows the Company to earn additional revenues. Thus, the decision to adjust for additional investments in Summer of 2008, while limiting revenues to only consider growth that occurred through the end of the test year is inherently arbitrary, creating a mis-match which is not theoretically sound. Accordingly, I recommend rejecting this adjustment. If attrition compensation is to be provided, I believe it can better be accomplished through a balanced, comprehensive approach as explained in the appendix to my testimony.

Q. Can you now discuss the Company's rate base adjustment 4 - Post Test Year Plant Additions?

A. Yes. APS has grouped into a single pro forma adjustment numerous construction projects that were on the Company's balance sheet by the end of the test year, and which it expects to be placed in service by the time rates in this case will take effect, sometime in 2009. [Id.] Mr. Kearns explains:

> As of December 31, 2007, the Company had incurred $623 million in costs related to utility construction projects to serve existing and future customers that had not been recorded as in-service at the end of the Test Year. After removing the dollars associated with the Palo

> Verde Unit 3 Steam Generator, the Cholla Capital Projects, Yucca Units 5 and 6, transmission projects, projects of relatively small dollar value, and projects not expected to be placed in service before rates from this case will take effect, $251.3 million Total Company and $244.8 million of items within the Commission's jurisdiction remains for projects that are either already in-service or that will be completed by the expected effective date of new rates. [Id., p. 29]

There are a total of 1,201 plant additions grouped into this adjustment. [Kearns Attachment DAK 12] The additions include 38 projects with an estimated cost of over $1 Million, 36 projects with an estimated cost between $500,000 and $1 million, and 1,127 projects with an estimated cost of $10,000 to $500,000. [Id.] By plant category, there are 169 generation projects; 986 distribution projects; and, 46 "other projects". [Id.] In total, these miscellaneous post test year plant additions increase rate base by $244.802 million. [SFR Schedule B-2]

Q. What is your conclusion with regard to these miscellaneous post test year plant additions?

A. None of the projects included in this adjustment were completed by my recommended cut-off date for these sorts of adjustments. With more than a thousand separate plant additions, it isn't practical to analyze or debate the merits of each item individually. However, in general, I would note that many of these projects were not completed or placed into service until long after the test year, and I don't believe the alleged attrition problem can be accurately resolved by picking and choosing an ad hoc series of adjustments for specific cost increases. As well, I would note that the

Company has ignored any offsetting cost decreases or revenue increases which will accompany these plant additions as and when they occur.

Given the importance of the attrition issue in this case, I believe it is preferable to adopt a uniform, consistent cut-off date as of the end of the test year, and to the extent the Commission decides it needs to go beyond the test year, it should do so in a systematic, comprehensive manner, rather than debating the merits of a series of ad hoc responses to specific portions of the overall situation. Furthermore, it is worth noting that the exact cost and completion date of many of these anticipate plant additions were not known when the Company prepared its testimony, and that this sort of adjustment is necessarily based on estimates that cannot possibly be perfect.

The ad hoc adjustment approach is inherently controvesial and fraught with imprecision. Even if the final construction cost is known, the related impact on the Company's income is not known or measurable. It is impossible to know precisely how these projects will impact the Company's operating costs. In some cases, there may be additional maintenance and other costs; in other cases, costs may actually decline, as older equipment is reinforced with new additions that increase reliability, or reduce the need to incur extraordinary labor costs to provide reliable service as the existing facilities near overload conditions. In any event, as new transmission and distribution facilities are added to the system it becomes feasible to serve load growth, which allows the Company to earn additional revenues. Yet, the Company has not made any adjustments for revenues associated with customer and sales growth occurring through the dates at which these various projects will be completed (well after the end of the test year).

Q. Can you now discuss the Company's proposed rate base adjustment 5 - West Phoenix Unit 4 Regulatory Disallowance?

A. APS witness La Benz explains:

> In accordance with GAAP, this disallowance was only recorded for regulatory purposes. Consequently, a pro forma adjustment is needed to reduce Rate Base by the disallowed amount. [La Benz Direct, p. 19]

This adjustment reduces rate base by $9.886 million.

Q. Did APS propose a similar adjustment in its previous rate case?

A. Yes. APS' filing in the previous rate case included a similar adjustment related to the West Phoenix Unit 4 regulatory disallowance. The adjustment was not opposed by any party, and was accepted by the Commission. [Decision 69663, p. 14]

Q. What is your conclusion with regard to this pro forma rate base adjustment?

A. I recommend the Commission accept this adjustment. This is the only rate base adjustment proposed by the Company that I have included in my revenue requirement calculations, as shown on Schedules BJ-3, BJ-4 and BJ-6.

Q. Are you recommending any rate base adjustments that were not included in the Company's filing?

A. Yes, one. First, I recommend making an adjustment to the Company's working capital calculations, to more accurately reflect the approach adopted by the Commission in the last rate case. During the discovery process the Company acknowledged that

> Although it was APS's intention to use the staff methodology from Decision No. 69663, in reviewing the detail supporting interest expense, it was noted that the calculation was not prepared consistent with the Staff methodology in the previous rate case. [APS Response to Staff DR 13.1]

Based upon the workpapers supplied by the Company in that discovery response, I have estimated the impact of revising the working capital calculation, consistent with the Staff methodology. The estimate impact is to reduce the total company cash working capital by $4,078,000 ($3,311,974 for the ACC jurisdiction).

V. Income Adjustments

Q. Let's discuss APS' proposed income adjustments. Can you begin by commenting on APS' income adjustments 1 through 4?

A. APS' first four income adjustments correspond to its first four rate base adjustments: Palo Verde Unit 3 Steam Generator; Cholla Generating Station Environmental Projects; Yucca Units 5 and 6; and, Post Test Year

Plant Additions. [See, SFR Schedule C-2] Each of these income adjustments includes the depreciation, interest expense and taxes related to the corresponding plant addition. As I explained earlier, these projects were not completed by the end of the test year, and the Company has not adequately analyzed any related cost decreases or revenue increases which will accompany these plant additions. The purpose of these adjustments, like the corresponding rate base adjustments, is to offset inflation and attrition after the test year. Accordingly, I recommend these adjustments be rejected. To the extent the Commission concludes that some additional rate relief is warranted, beyond that justified by the actual historical test year, due to the Company's weak credit metrics, I recommend that any such extraordinary relief be developed in a more systematic, comprehensive manner, as discussed in the Appendiz to my testimony.

Q. What is the purpose of APS' "attrition" adjustment?

A. This is the only adjustment that APS has explicitly labeled as being attrition-related. Mr. Kearns explains that even if all its other pro forma adjustments are accepted by the Commission, the Company

> would require an additional adjustment to revenue requirements in the amount of $79,278,000 in order to close the remaining gap between APS's revenue growth and its expense growth that will still exist at the time new rates become effective. [Kearns Direct, p. 31]

To calculate the amount of this explicit attrition adjustment, APS calculated its projected revenues and operating expenses for 2010, and compared the results to the Company's unadjusted test year revenues and expenses "in order to measure the change in annual operating income that the Company will experience from the unadjusted Test Year through year-end 2010." [Id., p. 4] The Company performed 2 additional calculations to account for the impact of all its other pro forma adjustments. First, it reduced its initial attrition-related operating income deficiency "by the operating income deficiency solved by the Company's pro forma adjustments to the Test Year income statement." [Id.] Next, APS added the increased revenue requirement related to financing the projects that the Company expects to undertake by 2010, "after reducing the total amount of those capital expenditures by the amount of related costs already captured in the Company's rate base pro formas." [Id., pp. 4-5] The result was a remaining attrition-related revenue requirement deficiency of $83 million in 2010, "a number that translates to a $79.3 million revenue requirement deficiency in the Test Year." [Id., p. 5]

Q. Are there problems with APS' proposed attrition adjustment?

A. Yes. First, APS' attrition adjustment places too much emphasis on its 2010 projected revenues and expenses. These projections may or may not be accurate, and they may or may not be consistent with historical attrition trends. The APS approach essentially converts the historical test year into a projected 2010 test year – something I would strongly urge not be accepted, either directly or indirectly.

Second, the Company has not adequately disentangled the development of its proposed attrition adjustment from the development of its other test year adjustments. To have any merit, such an analysis would need to carefully distinguish between adjustments that are or are not related to attrition (like the ones that annualize the rates approved in Decision No. 69663 and the ones that normalize maintenance expenses at a typical level). By failing to adequately disentangle the various adjustments, there is no assurance that the test year relationships are meaningfully perserved nor is there any assurance that the adjustments that are unrelated to attrition are not partly or entirely negated through the development of the Company's attrition adjustment.

Third, APS has not conclusively demonstrated that it has avoided any double counting of attrition compensation provided through other parts of its revenue requirement calculations, like the use of an end-of-period rate base. Accordingly, I recommend rejecting this adjustment, and substituting the approach to attrition that I explain in the appendix to my testimony.

Fourth, the APS approach provides too much attrition relief, too quickly. Even assuming the calculations were legitimate, and did not have the affirmities I've just mentioned, if they were accepted customers would be forced to pay rates in 2009 to compensate for cost increases that aren't projected to occur until 2010 and beyond. Perhaps the Company would contend that while the rates will be excessive during 2009 and much of 2010 things will eventually average out, since costs will eventually increase to the point where the rates are inadequate during 2011 and beyond. However, this is far too speculative an approach, and the possibility of having lower than optimal rates in effect during 2011 doesn't legitimize placing unreasonably high rates into effect in 2009.

Q. Can you discuss APS' fuel and purchased power income adjustments?

A. APS income adjustments 6 through 8 relate to fuel and purchased power expenses. First, APS proposes a base fuel and purchased power pro forma income adjustment, which increases the base fuel rate from 3.25 cents per kWh to 3.88 cents per kWh. [Ewen Direct, pp. 19-20] Base fuel expense is increased by approximately $184 million. [Attachment PME-1] However, approximately $170 million of this increase is offset by a corresponding reduction in future Power Supply Adjuster recovery, so the net impact on customers will be closer to $14 million. [Id.]

APS explains that it has been serving growth primarily with increased use of natural gas generation, which has become more expensive than it was when the current base fuel rate was approved. [Ewen Direct, p. 20] The proposed base fuel rate adjustments "recognize known and measurable changes to Test Year conditions and are more representative of conditions that will be present when the Company's new rates are likely to take effect." [Id., p. 21] $54 million of the proposed $184 million adjustment "reflects costs that are already reflected in the Test Year and the remaining $130 million is for costs that are normalized to 2010 levels." [Id.]

These pro forma adjustments are derived from APS estimates of future fuel expense, based on the "March 31, 2008 forward curve for natural gas and power prices and the corresponding valuation of the Company's hedges." [Id., p. 22] Mr. Ewen explains:

> The process I have used captures the impacts of the relevant factors on the Company's average base fuel cost. The change in the average cost from the Company's Test Year amounts applied to the adjusted Test Year retail sales amounts produces the appropriate adjustment for the Test Year pro forma. ...This base fuel rate results in a pro forma to Test Year fuel and purchased power costs of $129,649,000 (see SFR Schedule C-2, page 2, column 6). [Id., p. 23]

Next, APS removed revenues related to prior period fuel expense collected through the PSA from the Test Year, and it removed related prior period amortization of deferred fuel. This adjustment resulted in a pre-tax $13.309 million increase in operating income. [SFR Schedule C-2] Finally, APS removed the PSA fuel deferrals and deferred non-cash mark-to-market accounting entries from Test Year expense. [Ewen Direct, p. 27] According to Mr. Ewen, "these non-cash accounting adjustments have no bearing on the Company's anticipated fuel expenses in 2010 and beyond." [Id.] The pre-tax impact of these adjustments is a $189.969 million decrease in operating revenues. [SFR Schedule C-2]

Q. What are your conclusions regarding these fuel and purchased power adjustments?

A. I have no objection to shifting the recovery of costs from the PSA mechanism to base rates, and of course it is necessary to adjust the test year data to eliminate non-recurring events related to fuel costs incurred in earlier years. Thus, I have no objection to the adjustments in principle.

However, I recommend updating the calculations to reflect a more current view of anticipated fuel costs. Crude oil prices peaked during the summer of 2008, and have since collapsed. While natural gas prices don't move in exact lock-step with oil prices, the natural gas market is certainly influenced by the price of competing fuels, both in the short run and in the long run. To a lesser degree, coal prices may also be subjected to downward pressures due to a decline in global demand for energy that was not anticipated at the time the Company prepared its direct testimony. For this reason, as well as the overall decline in demand attributable the current economic recession, I would expect future fuel prices to be somewhat lower than those projected by the Company and utilized in its proposed adjustments.

Admittedly, great precision is not needed in projecting future fuel costs, since any over-estimates, or under-estimates will largely be negated by an offsetting change in future PSA recovery. Nevertheless, I recommend the Commission review the most recent available natural gas and coal cost information at the time of the hearing in this case, and update these adjustments to be consistent with that information. In developing the revenue requirement recommendations included with this prefiled direct testimony, I used the Company's originally filed calculations, as shown on BJ-8 and BJ-9 in columns (B), (C) and (D).

Q. Can you now discuss APS income adjustments 9 and 10 - Normalize Non-Nuclear Maintenance Expense and Normalize Nuclear Maintenance Expense?

A. Both of these adjustments are intended to restate maintenance expenses at a "normal" level, thereby excluding the impact of minor fluctuations in the amount of maintenance which is performed during any particular year. APS develops separate adjustments for nuclear and non-nuclear expenses, but the underlying rationale is the same in both cases.

APS has adjusted planned maintenance time and unplanned outage time "to be consistent with an average year". [Ewen Direct, p. 27] APS' non-nuclear maintenance adjustment results in a $1.947 million increase in operating income. [SFR Schedule C-2]. The analogous nuclear maintenance adjustment results in a $3.287 million increase in operating income.

Q. What do you conclude regarding these maintenance adjustments?

A. They are not absolutely necessary, since the differences the actual cost of outages and maintenance during the test year was apparently only slightly more than what would theoretically occur in a perfectly "normal" year. However, similar maintenance adjustments were accepted by the Commission in APS' prior rate case. While I am not vouching for the accuracy of the underlying calculations, I do not object to the adjustments in principle, since they are consistent with the underlying premise of a historical test year. The test year is simply a device for analyzing the normal level of revenues and costs which can be expected in the future.

Therefore, I have included income adjustments 9 and 10 in developing my recommended revenue requirements, as shown on BJ-8 and BJ-9 in columns (E) and (F).

Q. Can you now discuss APS income adjustment 11 - Normalize Weather Conditions?

A. This adjustment is intended to restate the test year results as if perfectly normal weather conditions had occurred. APS estimates that, primiarly due to abnormally hot weather conditions during the summer of 2007, electricity sales were 445,000 mWh greater than would have occurred if cooler weather had occurred. [Ewen Direct, p. 29] APS' weather adjustment results in a $13.318 million decrease in operating income. [SFR Schedule C-2].

Q. What do you conclude regarding the weather adjustment?

A. A similar adjustment was unopposed and accepted by the Commission in APS' last rate case. While I am not vouching for the accuracy of the underlying calculations, I do not object to this adjustment in principle, since it is consistent with the underlying purpose of using a historical test year, which is simply a device for analyzing the normal level of revenues and costs which can be expected in the future. Therefore, I have included this adjustment in developing my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (G).

Q. Can you now discuss APS income adjustment 12 - Annualize Customer Levels?

A. Yes. APS' customer count was greater at the end of 2007 than in any other month during the test year. [Ewen Direct, p. 31]

> Because the Company believes these customers are here to stay, the Company annualizes the Test Year's customer levels by assuming that the December level of customers had been present for the full year. [Id.]

APS' customer count adjustment results in a $13.658 million increase in operating income. [SFR Schedule C-2]

Q. What do you conclude regarding the customer adjustment?

A. A similar adjustment was unopposed and accepted by the Commission in APS' last rate case. As well, this adjustment is essential if the Commission is going to use an end-of-year rate base, as has been its typical practice. I therefore recommend that the Commission accept this adjustment. Although I am not vouching for the accuracy of the underlying calculations, I have used the adjustment amount proposed by the Company in developing my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (H).

Q. Can you now discuss APS income adjustment 13 - Normalize Uncollected Fixed Costs?

A. APS proposes an adjustment to recover revenues it expects to lose in the future, as a result of DSM programs.

> The Company will experience a loss in revenue due to a reduction in customer usage as these programs are implemented and become successful. The expected usage reduction from the implementation of programs in 2010 will be approximately 220,696 MWh. [Ewen Direct, p. 33]

Q. What do you conclude regarding income adjustment 13?

A. This is another post test year adjustment which largely attrition-related. In effect, APS is attempting to recover revenues that it believes it would potentially collect from customers several years after the test year, but for the presence of its DSM programs. APS proposed a similar adjustment in its previous rate case. The Commission rejected the proposal, stating:

> We agree with Staff and RUCO that APS' pro-forma conservation, or net lost revenue, adjustment to increase revenues should not be adopted. As testified to by Staff, a mechanism exists for APS to recover a portion of the actual energy efficiency savings from its successful DSM programs. We also agree that neither the adjustment nor its amount is sufficiently known and measurable to reasonably change the cost of service. Further, under the terms of the Settlement Agreement as approved by the Commission, APS is not allowed to recover net lost revenues in this case on a going forward basis. [Decision 69663, p. 31]

In the previous rate case, APS proposed to collect lost revenues from DSM programs up to 1 year beyond the test year. In this case, APS is attepting to recover estimated lost revenues up to 3 years beyond the test year. The resons for rejecting the proposal last time are equally applicable, if not more so, in this proceeding. Furthermore, I recommend that the Commission reject all of the post-test year adjustments. To the extent it is persuaded that additional attrition compensation is warranted in this case, I believe this can be accomplished more appropriately through a separate, comprehensive approach, as described in my appendix. Accordingly, I recommend the Commission reject this adjustment.

Q. Can you now describe APS income adjustment 14 - Annualize Spent Fuel Storage Costs?

A. APS offers only a very brief explanation of this adjustment. Mr. La Benz simply states:

> This pro forma adjustment for Spent Fuel Storage adjusts the Test Year to reflect the full year of the new cost level approved in Decision No. 69663. This results in a reduction to pre-tax operating income of $1,289,000. [La Benz Direct, p. 16]

Q. What do you conclude regarding income adjustment 14?

A. This adjustment appears to be analogous to an adjustment that was unopposed by any party and accepted by the Commission in APS' previous rate case. Although I am not vouching for the accuracy of the underlying calculations, I have used the adjustment amount proposed by the Company in developing my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (I).

Q. What is income adjustment 15 - Annualize Four Corners Reclamation Costs?

A. APS explains this adjustment as follows:

> This pro forma adjustment for Four Corners Coal Reclamation adjusts the Test Year to reflect a full year of the new amortization level as approved by Decision No. 69663. This results in a reduction to pre-tax operating income of $334,000. [Id.]

Q. What do you conclude regarding income adjustment 15?

A. This adjustment appears to be reflecting the full impact of revised cost calculations that were approved in the last rate case. Although I am not vouching for the accuracy of the underlying calculations, I have included an adjustment for this cost increase on BJ-8 and BJ-9 in column (J).

Q. Can you briefly describe income adjustment 16 - Annualize Bark Beetle Remediation Costs?

A. Yes. This adjustment annualizes APS' Bark Beetle remediation costs. APS states:

> Because the Test Year only contained amortization from July 1, 2007 through December 31, 2007 (6 months), a pro forma is necessary to add 6 months of amortization resulting in a full 12-month amortization of the bark beetle remediation costs in the Test Year. This results in a reduction to pre-tax operating income of $1,918,000 [Id., p. 17]

Q. What do you conclude regarding income adjustment 16?

A. This adjustment appears reasonable, although I am not vouching for the accuracy of the underlying calculations. Hence, it is included on BJ-8 and BJ-9 in column (K).

Q. Please describe income adjustment 17 - Annualize Depreciation and Amortization Per Decision No. 69663.

A. This adjustment increases depreciation and amortization expense "by applying the rates approved in Decision No. 69663 to the end of the Test Year plant balances..." [Id.] This adjustment results in an operating income reduction of $5.221 milion. [SFR Schedule C-2]

Q. What do you conclude regarding income adjustment 17?

A. This adjustment appears reasonable, and I recommend the Commission accept it. I have included it in my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (L), although I am not vouching for the accuracy of the underlying calculations.

Q. Can you now discuss income adjustment 18 - Remove Test Year Surcharges?

A. This adjustment is intended to exclude certain revenues and expenses that were not associated with base rates. The adjustment applies to the Environmental Portfolio Standard ("EPS") surcharge, Competition Rules Compliance Charge, and Regulatory Assessment charges. Mr. La Benz explains:

> These items are not collected as part of base rates so [they] must be excluded from the Test Year revenue in order to calculate new base rates. The pro forma also removes from expense the associated costs spent. In addition, the pro forma ensures that the Test Year reflects the $6,000,000

total amount authorized to be collected and spent as part of base rates under the EPS. This results in a reduction to pre-tax operating income of $1,436,000 (See Attachment JCL-8 and SFR Schedule C-2, page 6, column 18). [La Benz Direct, p. 18]

Q. What do you conclude regarding income adjustment 18?

A. Based upon the explanation offered by APS, it appears to be reasonable, so I have included this adjustment in my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (M).

Q. Can you now discuss income adjustment 19 - Annualize Sundance Overhaul Maintenance?

A. In Decision 69663 the Commission authorized APS to normalize non-routine Sundance overhaul expenses, and required the Company to recognize $1.609 million as a current period expense, and establish a concurrent regulatory liablity on its balance sheet. [Decision 69663, p. 17] According to APS, the accounting entries began on July 1, 2007. [La Benz Direct, p. 18] Adjustment 19 reflects an additional 6 months of Sundance overhaul expense. The after-tax effect is a $476,000 reduction in operating income. [SFR Schedule C-2]

Q. What do you conclude regarding income adjustment 19?

A. This adjustment appears to be consistent with Order 69663. Hence, I have included it in my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (N).

Q. Can you now discuss income adjustment 20 - West Phoenix Unit 4 Regulatory Disallowance?

A. This adjustment corresponds to rate base adjustment 5, discussed above. Consistent with my position on that issue, I recommend the Commission accept this adjustment. Hence, I have included it in my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (O).

Q. Can you now discuss income adjustment 21 - Interest Expense on Customer Deposits?

A. This adjustment captures the annualized interest cost associated with customer deposits. [La Benz Direct, p. 19] The adjustment results in a $1.371 million decrease in operating income. [SFR Schedule C-2] It is analogous to a similar adjustment that was unopposed by any party and accepted by the Commission in the prior rate case. Although I am not vouching for the accuracy of the underlying calculations, I have included it in my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (P).

Q. Can you now discuss income adjustment 22 - Depreciation Expense, 2007 Depreciation Study?

A. Adjustment 22 reflects changes in depreciation expense resulting from APS revisions to the depreciation rates approved in the Company's prior rate case. The new rates are based upon a recent depreciation study prepared by APS witness Ronald White. The depreciation adjustment results in a $5.840 million increase in operating income. [SFR Schedule C-2]

Q. What is your conclusion regarding adjustment 22?

A. I have not reviewed APS' new depreciation study, nor verified the accuracy of the underlying calculations, but I have included it in my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (Q).

Q. Can you now discuss income adjustment 23 - Annualize Payroll?

A. According to APS: "this pro forma adjustment increases Test Year expense mainly as a result of higher costs associated with a rising average salary and increased employee levels." [La Benz Direct, p. 20] In calculating this adjustment, APS used March 2008 employee levels, and a mixture of March 2008 and March 2009 wage levels. [Id.] The adjustment results in a reduction to operating income of $11.869 million. [SFR Schedule C-2]

Q. What is your conclusion regarding adjustment 23?

A. This is another post test year adjustment designed to ameliorate the impact of attrition. I recommend the Commission reject this adjustment since it goes beyond the end of the test year. To the extent the Commission concludes that additional rate relief is warranted, it should not deal with the attrition issue through a less disjointed, more comprehensive approach. I have incorporated a similar adjustment into my revenue analysis, but have used December 31, 2007 employee and wage levels, rather than the post test year levels assumed by APS. This modified adjustment is consistent with my recommended December 31, 2007 cut-off date.

Q. Can you now discuss income adjustment 24 - Normalize Employee Benefits?

A. This adjustment modifies the expenses associated with pension and Other Post-Retirement Employee Benefit ("OPEB") plans. The adjustment was calculated as the difference between actual test year expense, and the level of expense estimated for 2008. [La Benz Direct, p. 20] Essentially, APS has replaced actual 2007 expenses with anticipated 2008 expenses. The result of the adjustment is a $1.515 million increase in operating income. [SFR Schedule C-2]

Q. What is your conclusion regarding this adjustment?

A. The adjustment is another ad hoc attempt to deal with the alleged attrition problem. Since it is inconsistent with my recommended December 31, 2007 cut-off date, I recommend the Commission reject it.

Q. Please describe adjustment 25 - Normalize Income Tax Expense Including Synchronization of Interest.

A. This adjustment is described as an attempt to reflect "the Company's best estimate of on-going income tax expense." [Id., p. 22]

> The Company used a "top down" approach in computing cost-of-service income tax expense. This calculation, which was also adopted in Decision No. 69663, used the

> statutory rate and estimated 2007 levels of various tax credits and other permanent tax items ... It also considers the deduction of interest expense synchronized to the end of the Test Year's Rate Base. [Id.]

The result of this adjustment is a $3.878 million decrease in operating income. [SFR Schedule C-2]

Q. What is your conclusion regarding this adjustment?

A. It is reasonable to adjust the actual test year income tax expense to synchronize it with the rate base and cost of capital that is used in developing the Commission's allowed rate of return. Thus, for example, to the extent a portion of the Company's investment in West Phoenix 4 is being disallowed, it would be appropriate to adjust the actual income tax expense to eliminate the effects of tax-deductible interest expense supporting the disallowed investment.

Consistent with this philosophy, I have developed schedule BJ-11, using RUCO's recommended rate base and cost of capital levels. As shown on schedule BJ-9 in column (R), the net effect is to decrease ACC jurisdictional operating income by $11,856,000, which increases the revenue requiremnts by a larger amount than the Company's proposed adjustment.

Q. Please describe adjustment 26 - Annualize Property Tax Expense.

A. This adjustment is intended to replace the property tax expense that was actually incurred during the test year with a higher level of taxes that APS believes will be incurred in the future. Mr. La Benz explains that the proposed adjustment reflects "December 31, 2007 property values per the Arizona Department of Revenue and the 2007 tax year APS composite tax rate..." [La Benz Direst, p. 23] However, he goes on to explain that APS also incorporated other changes associated with post-test year events:

> In addition, this proforma takes into account the increase in property tax rates in 2009 after the temporary suspension (suspended from 2006 through 2008) of the State Equalization Assistance Property Tax Rate ends. In April 2008, the Governor vetoed a bill that would have made that suspension permanent. Also, the electric generation land values reflect the changes made by HB 2657 Chapter 203, which passed during the 2007 legislative session. [Id.]

The result of this adjustment is a $7.906 million decrease in operating income. [SFR Schedule C-2]

Q. What is your conclusion regarding APS' property tax adjustment?

A. As with many of its other attrition-related adjustments, the proposed adjustment is not based on a single, consistent time line or approach to dealing with the alleged attrition problem. In some respects it appears to simply increase taxes to reflect the end of year investment, but in other respects it appears to be an attempt to deal with changes that APS anticipates will occur after 2008. Consistent with my other attrition-related recommendations, I recommend this adjustment be rejected, and either the actual test year property taxes be used, or a narrower adjustment be developed to only reflect increases in property taxes resulting from increases in the Company's investment up through the end of the test year.

I have used a relatively simple approach to develop an end-of-year adjustment. I first determined the percentage increase in the Company's average net utility plant from the average during 2007 to the level that was present at December 31, 2007. As shown on Schedule BJ-10, this equates to a 3.58% increase. I then applied this percentage figure to the actual 2007 property taxes to develop my pro forma adjustment. As shown on Column (S) of Schedule BJ-8 and BJ-9, after considering the effect of income taxes, this adjustment results in a reduction in Total Company operating income of $2,589,000 and a corresponding reduction in ACC Jurisdictional operating income of $2,241,000.

Q. Can you now discuss income adjustment 27 - Amortize Navajo Coal Reclamation Costs?

A. Yes. APS is part owner of the Navajo Generating Station, and is apparently under contract with Peabody Coal Company to receive coal until April 30, 2011. [La Benz Direct, p. 23] APS has an option to extend this contract through April 30, 2026. The adjustment reflects a negotiated settlement with other parties, which will result in cost increases over the life of the contract. APS has assumed, in its calculations, that the option to extend the contract will be exercised. [Id., pp. 23-24] The result of the adjustment is a $136,000 decrease in operating income. [SFR Schedule C-2]

Q. What is your conclusion regarding this adjustment?

A. I have not studied this adustment in complete detail, however, it appears to be analogous to the Four Corners Coal Reclamation adjustment, which was accepted in the last APS rate case. As well, the settlement which gave rise to these cost calculations was apparently adopted during the test year. Accordingly, I have included it in my recommended revenue requirement calculations, as shown on schedule BJ-8 and BJ-9 at column (T).

Q. Can you now discuss income adjustment 28 - Annualize Workforce Reduction Savings?

A. APS apparently plans to reduce employee levels by approximately 100 during 2008. [La Benz Direct, p. 24] This adjustment reflects the changes in expenses associated with that anticipated reduction. The result of the adjustment is a $6.065 million increase in operating income. [SFR Schedule C-2]

Q. What is your conclusion regarding this adjustment?

A. A reductions in the number of employees is one of the types of cost redutions which helps ameliorate the alleged attrition problem. Since the anticipated cost savings won't be achieved until after my recommended December 31, 2007 cut off date, I recommend the Commission reject this adjustment.

Q. Please describe adjustment 29 - Normalize Customer Bad Debt Expense.

A. Mr. La Benz Explains:

> This pro forma adjusts customer bad debt expense to a level reflective of final, proforma weather-normalized, customer annualized Test Year operating revenues, and the average percentage of actual account write-offs experienced in the latest twelve month period available (twelve months ended April 30, 2008). [La Benz Direct, p. 25]

The result of the adjustment is a $593,000 decrease in operating income. [SFR Schedule C-2]

Q. What is your conclusion regarding the bad debt adjustment?

A. This adjustment is not absolutely necessary, since the net impact of all these various adjustments on the Company's bad debt expense is relatively minor. However, I don't object to making this type of adjustment, provided it is limited to the test year, and does not incorporate changes in the bad debt rate occurring after the test year. RUCO asked the Company to recompute the adjustment excluding the post test year elements. APS explained that no restatement was necessary since this adjustment "is not for actual or projected operations beyond the end of the test year. The adjustment is to recognize bad debt expense anticipated on test year revenues." [APS Response to RUCO DR 10.6] While there is some ambiguity in this response, it appears that the intent is more a matter of synchronizing or matching the bad debt expense to the test year revenues, rather than an attempt to reflect higher levels of bad debt expense after the end of the test year. Accordingly, I have included the adjustment in my developing my recommended revenue requirement calculations, as shown on schedule BJ-8 and BJ-9 at column (V).

Q. Please describe adjustment 30 - Miscellaneous Out-of-Period Adjustments.

A. This adjustment is intended to exclude items recorded in the test year which relate to events which occurred prior to the test year, and to include items recorded outside the test year which relate to events during the test year. Mr. La Benz explains that the adjustment "combines several smaller entries that fit this description." [La Benz Direct, p. 25] The result of the adjustment is a $2.367 million increase in operating income. [SFR Schedule C-2]

This adjustment appears to be reasonable, and analogous to a similar adjustment that was unopposed by any party and accepted by the Commission in the prior rate case. I therefore have included it in my recommended revenue requirement calculations, as shown on schedule BJ-8 and BJ-9 at column (V).

Q. Can you now discuss income adjustment 31 - 50% of Lobbying Expenses?

A. APS Witness Rumelo explains this adjustment as follows:

> APS's lobbying activities benefit APS customers, and this pro forma calculates that portion (50%) of the Company's lobbying expenses that the Commission deemed

> acceptable for recovery in Decision No. 69663. [Rumelo Direct, p. 8]

The result of the adjustment is a $829,000 decrease in operating income. [SFR Schedule C-2]

Q. What is your conclusion regarding the lobbying cost adjustment?

A. Pursuant to the FERC's Uniform System of Accounts (USOC), there is a presumption of non-recovery of lobbying costs, and utilities are therefore required to record these expenses "below the line". [See, Decision 69663, p. 34] In the prior rate case, in violation of USOC requirements, APS recorded a portion of its lobbying expenses above the line, effectively seeking recovery of that portion of these costs from ratepayers. In response, RUCO witness Marylee Diaz Cortez analyzed the above-the-line portion of APS' lobbying costs, and recommended disallowing 100% of certain portions of the above-the-line lobbying costs, and disallowing 50% of other portions of the above-the-line costs. [See, Diaz Cortez Direct, Docket No. E-01345A-05-0816, August 18, 2006, pp. 25-27] The Commission concluded Mrs. Diaz Cortez' adjustment was reasonable. [Decision 69663, p. 35]

Notwithstanding APS claims to the contrary, the Commission did not conclude that APS should be entitled to recover from ratepayers 50% of all of its lobbying costs. In fact, it did not guarantee recovery of any lobbying costs. Rather, it concluded that, in the future, if APS seeks recovery of lobbying costs, it "must provide the itemized lobbying costs associated with each benefit it alleges resulted from the specific lobbying activity." [Id.]

In this proceeding, APS has not complied with this requirement, nor has it demonstrated that any of the lobbying costs it seeks to recover directly benefit ratepayers. Accordingly, I recommend the Commission reject this adjustment.

Q. Can you now discuss income adjustment 32 - SurePay/AutoPay Discount?

A. In APS' prior rate case, APS demonstrated that it experienced cost savings of $0.48 per month for each SurePay or AutoPay customer, for an annual savings of approximately $820,000 per year. [See, Decision 69663, p. 100] The Commission therefore concluded that APS should be allowed to increase its test year expenses by $820,000 and to provide a monthly discount of $0.48 to SurePay and AutoPay customers. [Id., p. 101] Adjustment 32 annualizes the decreased revenue associated with this discount, resulting in a $466,000 decrease in operating income. [SFR Schedule C-2] This adjustment appears consistent with the Commission's prior order, and I have included it in my recommended revenue requirement calculations, as shown on schedule BJ-8 and BJ-9 at column (W).

Q. Finally, can you now discuss income adjustment 33 - Annualize Rates?

A. This adjustment is intended to adjust the test year revenues to reflect the impact of the the new rates that went into effect mid-year 2007. The effect is to increase operating income by $84.920 million. Absent this adjustment, the test year results would reflect a mixture of the previously approved rates and those that were adopted in Decision No. 69663, making it difficult to compute the amount of any rate increase that might be warranted in this case. Although I am not vouching for the accuracy of the underlying calculations, an adjustment of this type is necessary, and I have included it in my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (X).

Q. Are you proposing any income adjustments that were not included on SFR Schedule C-2?

A. Yes, I am proposing one such adjustment. APS offers a Supplemental Executive Retirement Plan (SERP) to high-ranking executives. This form of compensation is in addition to the regular retirement plan generally available to APS employees. On Febuary 23, 2006, in a decision involving SWG, the Commission held:

> [T]he provision of additional compensation to SWG's highest paid employees to remedy a perceived deficiency in retirement benefits relative to the company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other SWG employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other

> employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers. [Decision No. 68487, p. 18]

In APS' previous rate case, the Commission held:

> APS has not demonstrated any reason to treat the SERP expense for its SERP eligible employees any differently than our determination of SERP expenses associated with SWG employees. Accordingly, we find that the SERP expense should not be recovered from APS ratepayers, and accordingly, will reduce operating expense in the amount of $3,93 1,467. [Decision 69663, p. 27]

APS is again seeking to recover these costs from ratepayers.

> With due respect to the Commission, APS believes that the Commission erred in disallowing SERP in its last rate case and asks the Commission to reconsider the issue now. [Brant Direct, p. 82]

However, the Company has not offered any new evidence to overcome these past rulings. Accordingly, I assume the Commission will once again want to make this adjustment, and thus I have included one in my recommended revenue requirements, as shown on BJ-8 and BJ-9 in column (Y).

Q. Do you have any final comments concerning the adjustments you have discussed above?

A. Yes. I would like to reserve the right to modify these calculations as well as my specific recommendations, to the extent new information becomes available after I file this testimony. In particular, I will review the Staff's direct testimony as well as the Company's rebuttal testimony, and I may modify some of the positions set forth above on the basis of information gleaned from those filings.

V. Conclusions and Recommendations

Q. Can you now summarize the result of your recommendations?

A. Yes. My recommendations are summarized on Schedule BJ-1. My rate base recommendations result in an ACC jursidictional original cost rate base of approximately $4.936 billion, an RCND rate base of $9.642 billion, and a fair value rate base of $7.289 billion, assuming the Commission follows its traditional 50/50 weighting. This compares to the Company's rate base proposals of $5.360 billion, $10.067 billion and $7.713 billion for original cost, RCND and fair value, respectively. After taking into account pro forma adjustments that aren't related to attrition, the test year operating income is $285.1 million, compared to the Company's proposed operating income of $203.1 million.

Q. How does your revenue requirement compare to the Company's?

A. Applying RUCO witness Rigsby's recommended overall cost of capital of 7.70% and recommended fair return on fair value of 5.21% to my recommended rate base indicates required operating income is $380.0 million. My analysis (excluding post-test year attrition compensation) results in an income deficiency of $94.9 million, using RUCO's recommended cost of capital.

Q. What increase in revenues is implied by this income deficiency calculation?

A. Applying the Company's gross revenue conversion factor to this test year income deficiency results in a base rate revenue increase (excluding attrition) of $156.6 million or an increase of 5.70% over current base rates. This is less than half the Company's requested revenue increase of $448.2 million.

Q. APS explains that a portion of its revenue increase would have been collected from the PSA anyway, and that the net increase is only $278.2 million. Applying similar logic to RUCO's recommendations, what is the net revenue increase?

A. After subtracting the same $169.977 million PSA offset, it appears that no increase in rates is warranted based on the actual test year results. In fact, RUCO's recommended revenue requirement calculations suggest that, excluding any consideration of post-test year attrition, the 2007 test year results do not indicate any need for a rate increase, at least assuming RUCO's recommended rate of return is accepted. If the analogous calculations were performed using the 10.75% cost of common equity adopted by the Commission in the last case, the net effect would be a rate increase of approximately $36.2 million, excluding attrition compensation.

Q. Is RUCO recommending a rate reduction in this case?

A. No. Given APS's weak credit metrics, RUCO is not recommending a rate reduction, notwithstanding the fact that the actual test year results might suggest one would normally be appropriate.

Q. Does this conclude your testimony, prefiled on December 19, 2008?

A. Yes, it does.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

Other Government Agencies

Canada—Department of Communications
Hillsborough County Property Appraiser
Provincial Governments of Canada
Sarasota County Property Appraiser
State of Florida—Department of General Services
United States Department of Justice—Antitrust Division
Utah State Tax Commission

Regulated Firms

Alabama Power Company
Americall LDC, Inc.
BC Rail
CommuniGroup
Florida Association of Concerned Telephone Companies, Inc.
LDDS Communications, Inc.
Louisiana/Mississippi Resellers Association
Madison County Telephone Company
Montana Power Company
Mountain View Telephone Company
Nevada Power Company
Network I, Inc.
North Carolina Long Distance Association
Northern Lights Public Utility
Otter Tail Power Company
Pan-Alberta Gas, Ltd.
Resort Village Utility, Inc.
South Carolina Long Distance Association

Stanton Telephone
Telecomnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

Other Private Organizations

Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Casco Bank and Trust
Coalition of Boise Water Customers
Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
PenBay Memorial Hospital
Rosebud Enterprises, Inc.
Skokomish Indian Tribe
State Farm Insurance Company
Twin Falls Canal Company
World Center for Birds of Prey

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. As a result of my experience with the Florida Public Counsel and my work as a consulting economist, I have been actively involved in approximately 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Many of the resulting reports were prepared for the internal use of the Florida Public Counsel. Others were prepared for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

Appendix B
Attrition

Q. What is attrition?

A. In the regulatory context, the term "attrition" generally refers to the phenomenon of a utility's profitability eroding over time.

Q. How is attrition measured?

A. Attrition is measured by comparing data over a series of years, to observe whether profitability remains reasonably stable, or is steadily deteriorating over time. For example, if the achieved NOI relative to net plant steadily falls from 8 percent in year 1, to 7 percent in year 2 to 6 percent in year 3, one might conclude that attrition of 1 percent per year has been occurring. To develop a meaningful and reliable measure of attrition it is imperative to develop the data over a reasonably long time period. The mere fact that profitability declined from one year to the next is not sufficient to conclude that an actual attrition problem exists, for this could be a mere fluctuation in the operating results from one year to the next.

Attrition can be calculated several different ways. For example, one can focus on absolute declines in net operating income (NOI), declines in NOI relative to net plant, or the rate of decline relative to revenues.

Q. What causes attrition?

A. All factors which help determine profitability, or the overall rate of return can potentially contribute to, or mitigate, attrition. In general, changes in the utility's revenues, expenses and investment can influence whether attrition occurs, and the amount of any attrition which is experienced. If growth in investment and growth in expenses outpaces growth in revenues, attrition will occur. Conversely, if revenues grow faster than costs, the opposite of attrition, which is called "accretion" will occur.

Although the underlying causes of attrition are numerous and varied, in most cases attrition is attributed to one or more of these root causes: inflation; growth in capital investment per KWH or per customer; and, regulatory lag, which delays recovery of cost increases. A serious, continuing pattern of attrition is typically associated with a fairly standard set of factual circumstances. In essence, inflationary pressures outstrip the benefits of increasing economies of scale, technological progress and increasing operating efficiency. Assuming the utility is allowed to pass fuel and purchased power cost increases through to consumers, the most likely circumstance in which a utility might experience continued erosion of its profitability (attrition) is when the utility is investing substantial amounts in additional plant and equipment with higher unit costs than its existing facilities – aswsuming the adverse impact of inflation on these new investments outweighs the beneficial impact of increased economies of scale that often accompanies such growth.

Q. Have you looked at the APS's situation specifically?

A. Yes. APS has been experiencing substantial growth in its capital investment. This can be seen whether one focuses on assets, or the invested capital that supports those assets. Construction expenditures totaled $808 million, $660 million and $897 million in 2005, 2006 and 2007 respectively. [Schedule A-4] At the time it filed its Amemded Application, APS projected construction expenditures totaling approximately $1 billion per year for 2008 through 2010.[1] [Id.] APS explains:

> The primary reason for the Company's increase in unit costs is the capital investment required to meet the Company's growth in customers and electricity demand while maintaining and improving its existing system. [Ewen Direct, p. 7]
>
> APS is required to spend upwards of one billion dollars per year over the next several years both to meet its continuing growth in customer and electricity demand and to maintain its existing system... [Id., p. 8]

Q. What claims does APS make regarding attrition?

A. APS focuses on return on equity in its discussion of attrition. For example, Mr. Brant states: "If Net Income does not increase as rapidly as equity investment, ROE Attrition will occur." [Brant Direct, p. 4] He went on to explain:

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

Mr. Brant claims that attrition is to blame for a total Company cumulative earnings shortfall of $321 million between 2003 and 2007 and could result in an additional $384 to 454 million reduction in earnings through 2010.

1 APS has since revised its projected capital expenditures to $894 million, $708 million and $917 million for 2008-2010. [see, APS Late Filed Exhibit 22]

[Id., pp. 26-27] However, these computations do not simply look at erosion of profitability over time. They also reflect the impact of other factors, like regulatory treatment of imprudent costs, which are not related to attrition as it is appropriately defined.

Q. Are there problems associated with attempting to determine whether APS is experiencing attrition, and if so, evaluating the magnitude of the problem?

A. Yes. First, there is no universally accepted methodolgy for measuring attrition. Second, the task is complicated by the effects of extraneous variables. For example, fluctuations in weather conditions, fluctuations in fuel prices, variations in generating plant availability and downtime for refueling and maintenance, and other factors can all influence the level of earnings, or rate of return, experienced by a utility during any particular year. As a result, any attempt to measure the erosion of earnings or return over time will be fraught with difficulties due to the impact of fluctuations in those variables, particularly if the analysis is limited to just a few years.

If a relatively cool year is followed by a relatively hot year, revenues and income may grow rapidly from one year to the next, masking the effect of any long term attrition which may actually be occurring during that time period. Similarly, if the opposite pattern occurs, and a relatively hot year is followed by a relatively cool year, revenues may flatten or decline, and income may fall rapidly from one year to the next, creating the impression of a severe attrition problem, whereas in reality, little or no attrition might actually be occurring – as would be readily apparent if normal weather had occurred in both years.

It is important to recognize that managment decisions can also be significant. Since both investment and expenses can be influenced by management decisions, and in general unit costs are sensitive to increases or decreases in efficiency and productivity, a utility's attrition rate should not be viewed as entirely outside the firm's control.

Q. Did APS raise the attrition issue in its previous rate case?

A. Yes, in its last rate case APS made essentially the same arguments that it has put forth in this proceeding. As summarized by the Commission:

> APS says the reason for the earning shortfall is the need to fund a huge capital expenditure program in recent years, coupled with the regulatory lag in recovering those expenses as part of rate base. [Decision No. 69663, p. 54]

APS requested an attrition allowance of between 1.7 percent and 4.1 percent, to be added to the allowed return on equity. [Id.]

Q. How did the Commission respond to APS' requested attrition allowance?

A. The Commission did not adopt APS' proposed attrition adjustment. The Commission was reluctant to grant extraordinary relief, since the Company did not offer sufficient evidence:

> APS argues that using an historical test year approach will not provide adequate revenues and to support that argument, APS uses projected financial information and assumptions about events that may or may not occur in the future.[Id., p. 62]

The Commission also noted that APS' projected financial information failed to account for the positive effects of other measures adopted by the Commission, and was therefore unreliable. Specifically, the Company's analysis did not consider the beneficial effects of the revised PSA mechanism adopted by the Commission. The Commission explained:

> The PSA mechanism adopted in this Decision uses a higher base cost of fuel and purchased power, and it also incorporates a forward-looking cost of fuel and purchased power that is based upon projected costs that are expected to be experienced during the time that PSA adjustor is in effect. It does not contain a "cap" on the total amount of costs, it does have an annual 4 mil bandwidth limit, and the 90/10 sharing provision was modified per APS' request to exclude certain types of costs. This new PSA will have a dramatic effect on APS' ability to timely recover its costs, and upon its cash Essentially, APS will collect more of its costs sooner. [Id., p. 63]

Finally, the Commission noted that APS' analysis failed to consider certain efficiencies that would occur as new customers were added to the system.

> After reviewing and analyzing all the testimony and evidence, we find that the evidence presented by APS does not conclusively show that the costs of growth will exceed the revenues accompanying the growth. The exhibits presented by APS in support of its argument are very general and do not include an analysis of offsetting economies of scale or other efficiencies that will occur as Fixed costs are spread over more customers. [Id., p. 64]

> As the number of customers increases over time, total revenues will increase, but whether total expenses will increase proportionally, is unknown and unknowable. This is because some "fixed" expenses built into existing rates and charges can be spread over more customers before the expense level increases. [Id., p. 65]

Q. What claims does APS make regarding regulatory policies and their influence on attrition?

A. APS points to credit rating agencies, who, according to APS, consider Arizona to be a "challenging regulatory environment" due to the length of time it takes to work through a rate case. [Brant Direct, p. 41] APS states:

> In APS's remarkable capital expenditure environment (one requiring capital expenditures of one billion dollars per year for the next three years), a policy that couples significant regulatory lag with the use of an historical test year in setting rates causes APS to be unable to recover the millions of dollars it has already lost because of attrition, and will ensure that attrition continues. [Brant Direct, p. 2]

> Coupled with a regulatory lag of up to 18 months to two years between the end of the test year and the time rates become effective, the historical data used in setting the Company's rates is inevitably stale and unrepresentative of conditions that will exist when the new rates are effective. Earnings attrition naturally results from this rate-making model any time that costs rise faster than revenues after the end of the historic test year. [Brandt Direct, pp. 31-32]

Q. Can regulatory policies influence the level of attrition?

A. While "regulatory lag" is not the root cause of attrition, it does exacerbate the problem. Given a general pattern of costs rising faster than revenues, significant attrition can occur from the time of the test year until the time when rates go into effect, and beyond that throughout the time period while a given set of rates remain in effect.

Whether or not the concept of attrition has been explicitly analyzed as such, it has always been a concern – one which has prompted this Commission and others to deviate from a purely historical test year – by using an end-of-period rate base, rather than an average rate base, and by accepting adjustments for "known and measurable changes," including adjustments for plant additions which occurred after the test year.

These regulatory policies can potentially overcompensate for inflation and attrition since the adjustments can potentially distort the test year results by creating a mismatch, in which revenue growth that occurred beyond the test year is overlooked or intentionally ignored, yet cost increases after the test year are carefully identified, measured, and included through a series of pro forma adjustments.

However, if the utility is experiencing relatively severe attrition, and the regulatory commission does not adjust its procedures to sufficiently compensate for the problem, rate relief that is granted through a traditional adjusted historic test year may not be sufficient for the utility to achieve the full amount of its allowed rate of return. As well, with the traditional rate making approach the utility may file a series of back-to-back rate cases, in an effort to "catch up" or keep pace with the attrition problem.

While the traditional approach of relying on an historical test year and making a series of ad hoc pro forma adjustments for known and measurable changes may be adequate under normal circumstances, it may fall short during a period of unusually heavy capital investment and growth, or a period of unusually rapid inflation. As well, this traditional approach is problematic, because it does not offer a sound theoretical or empirical basis for determine how much attrition relief is needed, or for determining whether too much attrition compensation is being requested.

Q. Have you attempted to test the claims made by APS that it is experiencing attrition?

A. Yes. As I explained earlier, attrition is measured by comparing analogous data from year to year. In making these sorts of comparisons, it is preferable for all of the data to be developed on a reasonably consistent basis from year to year. The key question is whether profitability remains reasonably stable, fluctuates, or is steadily deteriorating over time.

To evaluate the alleged attrition problem, I examined historical and projected financial and operating statistics provided by APS in its direct filing and through the discovery process. The data I primarily focused on covered the historical years 2005 through 2007, as well as the Company's projections for the years 2008 through 2010. I primarily focused on revenues, expenses, income, net utility plant, customer counts and sales volumes. While I believe some consideration of an even longer time period would be beneficial, given the Company's claims that attrition had worsened recently, and its stress on the very recent past and the near future, I focused my attention on the 2005-2007 time period, with a more limited consideration of the partly projected 2005-2010 time period, and the longer 1997-2007 historical time period.

Q. Can you explain what you found in your examination of this data, starting with revenue?

A. Yes. I began by examining year over year changes in revenues. In order to ensure a clean "apples to apples" comparision, we asked APS to restate the revenues, expenses and income amounts shown on SFR Schedule A-2 on a consistent, normalized basis. [See, RUCO Data Requests 8.2 through 8.4] Specifically, we asked APS to provide a revised version of this schedule which restates the amounts for Year Ended 12/31/2005, Year Ended 12/31/2006 and Actual 12/31/2007 based on the following assumptions: a) the rate changes that went into effect on July 1, 2007 had gone into effect on or before January 1, 2005, thereby showing what the revenues, income taxes and other amounts would be under the hypothetical assumption of a consistent set of rates through the entirely of all of these years; and, b) perfectly normal weather had occurred throughout each of these years.

As shown on Schedule BJ-14, after adjusting the data to remove the effects of abnormal weather and rate changes, as computed by the Company in its response to RUCO's data request, revenues are shown to have increased by 5.0% from 2005 to 2006, then by 2.6% in 2007, the test year. The Company projects revenues will increase 11.4% from 2007 to 2008, remain essentially flat from 2008 to 2009, and then increase 4.1% from 2009 to 2010.

Since this data reflects normalized weather and consistent rates, I would have expected to see a more stable pattern in the projected data – the unusually high growth rate projected for 2008 data and the subsequent unusually low growth rate in 2009 is somewhat odd, calling into question the validity of these projections. However, the fluctuations largely cancel out, leaving an average annual increase over the 2005-2010 time period of 4.63%. The latter figure seems reasonable, and is fairly consistent with other data relating to past and projected future growth in Arizona. Accordingly, I have given at least some limited consideration of the

Company's projected data in my attrition analysis, despite having general reservations about relying on projections, as well as specific concerns about these year-to-year fluctuations.

Q. Did you also look at changes in customer counts and kWh sales which contribute to this pattern of revenue growth?

A. Yes. I started by examining growth in retail customers from 2005 through 2010. As shown on Schedule BJ-14, retail customers grew by 4.4% and 3.3% in 2006 and 2007, respectively. APS is expecting retail customers to grow by just 1.5% in 2008 and 2009, then by 3.1% in 2010. The average annual growth in retail customers is 2.53% over this entire time period. I also examined growth in retail MWH sales. As shown, sales grew by 5.2% in 2006, dropping to 2.6% in 2007 and they are projected to grow by 1.0% in 2008. Sales are projected to grow by slightly less than 2.0% in 2009 and 2010. On a per customer basis, retail sales have been fairly constant, and are projected to remain essentially the same through 2010.

Growth in revenues per retail customer is expected to average slightly more than 2.0% per year over this time period. With the exception of 2008, growth in revenues per retail customer has been, or is expected to be, 2.0% or less each year.

Q. Can you explain what you found in your examination of operating expenses and investment in net plant?

A. Yes. Revenue deductions and operating expenses are expected to increase at an average annual rate of 5.27%. This outstrips growth in revenues, and as a result net operating income is expected to increase at an average rate of just 0.85% per year for the overall 2005-2010 time period. This stands in contrast to the historical and projected growth in net utility plant over this same time period. As shown, net plant grew by 4.2% from 2005 to 2006, and by 7.4% from 2006 to 2007. Annual growth in net plant is expected to continue to grow at a fairly rapid pace from 2007 to 2010. For the entire 2005-2010 time period, the data suggests an an average annual growth rate for Net Utility Plant of 6.62%. Combining this data with the comparable data for retail customers, it appears that Net Utility Plant per customer is growing at an average rate of 4.01% during 2005-2010.

Overall, this data is fairly consistent with the picture APS paints in its testimony, particularly with respect to relatively rapid growth in capital investment in recent years, and the anticipation of some slowing in this expected growth rate during the next few years.

It worth noting that on an average annual basis there are indications that both expenses and net plant are growing faster than revenues, and this pattern is seen in both the historical data and in the projected data. As I explained earlier, when costs are growing faster than revenues, profitability will tend to decline, and if this pattern is repeated year after year, it is fair to conclude that attrition is occurring. As well, it is also worth noting that I would anticipate a slowing in projected customer and sales growth, as well as a reduction in capital expenditures going forward, as a result of the recent slowdown in both the national and state economy.

Q. Have you made any effort to estimate the extent of attrition?

A. Yes. I performed several different calculations which may be helpful to the Commission, if it is persuaded that some deviation from its traditional ratemaking methodologies is warranted given the situation with respect to APS' credit metrics and bond ratings. First, I observed that NOI has been relatively stable, but it has not been growing as fast as Net Plant. Accordingly, I calculated net operating income as a percentage of net plant on an annual basis, and I then measured the change in this statistic from year to year. As shown on Line 4 of Schedule BJ-14, net income as a percentage of net plant is indicated to be trending down at an average annual rate of .24% during the recent historical period 2005-2007. A slightly higher rate of 30% is projected for 2007-2010. Combining this historical and projected data, the overall average rate of decline is .28% for 2005-2010.

Second, I converted these annual rates of change in profitability into equivalent dollar amounts on a year-over-year basis. More specifically, I started with the 2006 change in return on net plant of -0.1% and I multiplied this percentage figure times the 2005 net plant amount of $7.141 billion. This indicates an increase in profitability of $7.566 million year over year. Using this same procedure, I estimated that APS had experienced a decline in profitability of $43.328 million from 2006 to 2007. Using the same approach, I determined that the Company's projections for 2008 imply a reduction in profitability of $12 million from 2007 to 2008, following by a decline of $54 Million in 2009 and $12 million in 2010.

Although the declines are fairly moderate, considering their repetitive nature, it is reasonble to conclude that APS has been experiencing, and is projected to continue to experience, mild attrition. The calculated attrition rate and corresponding dollar amount of attrition is fluctuating quite a bit from year to year, and any single year's data isn't necessarily reliable.

Q. Have you developed any calculations that could be used by the Commission if it decides to provide compensation for attrition?

A. Yes. If the Commission concludes that some deviation from its historical practice is appropriate in this case, these calculations can provide a reasonable basis for estimating the appropriate magnitude of any attrition compensation. More specifically, on Line 6 of Page 1 of BJ-14 I this downward trend in profitability as a percentage of revenues. I started with the annual dollar amounts just discussed, and I compared these amounts as a ratio relative to the corresponding year's annual revenues. The results are shown on Line 6 of page 1 of Schedule BJ-14. By these calculations, it appears that APS experienced negative attrition (accretion) equivalent to 0.3% of revenues in 2006, followed by attrition equivalent to 1.5% of revenues in 2007. The Company's projections anticipate attrition as a percent of revenues of 0.4%, 1.7% and 0.4% in the years 2008, 2009 and 2010, respectively. While this data for individual years isn't necessarily significant, the overall pattern suggests an average annual rate of attrition of .55% during 2005-2007, and .75% during 2005-2010.

Q. What are the benefits of measuring attrition in this manner?

A. As I explained above, in APS' previous rate case, the Company was criticized by the Commission for failing to present a balanced picture of the attrition issue, and by failing to adequately analyze the increased efficencies that tend to occur as new customers are added to the system. The Commission noted that, in measuring attrition, one must also consider the economies of scale associated with spreading fixed costs over a larger customer base.

The approach I have just set forth presents a balanced picture, taking into account the extent to which economies of scale and increased efficiencies are, or are not, offsetting the higher costs associated with increased investment and inflation. As well, by restating the measured change in profitability or attrition as a percent of revenues, it is feasible for the Commission to directly gain a clear picture of the relative magnitude of downward trend in profitability, and to visualize the extent to which rates would need to increase in order to offset this trend.

Q. What have you concluded regarding APS' attrition situation?

A. The results of my analysis show that APS has been experiencing mild attrition, and it's projections suggest the problem is expected to continue over the next few years. Overall, however, the attrition that occurred during 2005-2007 was not extreme, and the Company's forecast for the 2007-2010 period suggests a continuation of this pattern of relatively mild attrition. In and of itself, this data does not provide any reason to conclude that APS is experiencing an extraordinary problem with attrition – one that is pervasive or serious enough to warrant deviating from the Commission's long standing regulatory policies.

However, the Commission might conclude that some attrition compensation is warranted in this case, in order to help bolster the Company's credit metrics and maintain or improve its bond ratings. If the Commission reaches this conclusion, the data provided in BJ-14 can be useful in determining the appropriate magnitude of any such compensation.

Q. Can you please briefly summarize APS' proposed response to the attrition situation?

A. Yes. As I discuss in my direct testimony, APS is proposing a series of pro forma adjustments which increase the rate base by adding investment that did not actual provide service to customers during the test year, and which reduce the test year operating income to reflect cost increases which didn't occur until 2008, or which are expected to occur at some point during 2009 or 2010. Notably, these adjustments are not fully consistent with each other, and they create severe distortions by matching 2007 revenues with cost levels that won't be incurred until 2008, 2009 or 2010, depending upon the particular expense item.

In addition to these implicit attrition adjustments, APS is proposing an additional $79.3 million increase in revenues as an explicit attrition adjustment. APS calculated this amount by first calculating the Company's projected revenues and operating expenses for 2010, and comparing those to unadjusted Test Year revenues and expenses "in order to measure the change in annual operating income that the Company will experience from the unadjusted Test Year through year-end 2010." [Kearns Direct, p. 4] The Company then reduced this calculated revenue deficiency by an amount related to its various pro forma adjustments, to arrive at the portion of its calculated deficiency which it seeks to recover using the explicit attrition adjustment. [Id.]

Q. Are there problems associated with APS' proposed solution?

A. Yes. As I explained in my direct testimony, extending adjustments farther and farther beyond the test year is an inherently arbitrary process which undermines the concept of relying on a test year to evaluate a utility's financial condition. It is an unavoidably arbitrary and fundamentally unsound approach – one which degenerates into guestimates about what might or might not happen far beyond the test year. Further, by limiting the specific adjustments to only consider growth in customers, sales and revenues through December 2007, while extending the range of cost related adjustments to include a wide variety of different phenomena stretching into 2010 results in an extreme violation of the fundamental principle that financial and accounting data ought to be carefully aligned to avoid mismatches.

By creating extreme mismatches between revenues and costs the calculated amount of rate relief is sharply boosted, presumably in an effort to compensate for the perceived attrition problem. But, this is an arbitrary process, which does not provide a sound basis for judging how much attrition relief is needed, how much is being provided, and whether the amount of relief being requested is excessive. In fact, the effect of this process is to virtually obliterate the historical test year, making it nearly impossible to use the adjusted data to evaluate the extent to which an earnings shortfall does or does not exist, or to judge the extent to which the requested rate relief is or is not merited.

Furthermore, because this process relies so heavily on projections, it tends to create an incentive for the Company to overstate its projected cost levels. If the proposed explicit attrition allowance were accepted it could weaken the incentive for the Company to operate efficiently and to constrain costs in the future (since future cost-cutting efforts will have the perverse tendency to make the Company's previous projections appear to have been inflated).

Q. Can you elaborate on the need to maintain incentives for utilities to operate efficiently?

A. Yes. One of the fundamental problems to be resolved by any method of monopoly regulation is how to maintain strong incentives for management to operate the firm efficiently. It would certainly be possible to provide public utility services on a pure cost-plus pass through basis, so that a dollar spent in month one is recovered from customers in month two. But such a cost-plus system would be highly undesirable, since it would completely negate any incentive for cost controls and efficiency.

The need to encourage efficiency, and to discourage wasteful spending is one of the reasons why public utility regulation has typically relied upon the use of an historical test year, which is carefully reviewed and analyzed by the regulatory body. Under this form of regulation, a utility's costs are periodically reviewed and audited, and there is always the risk of a disallowance of unnecessary or imprudent investments or excessive costs. This review process has to a large degree been successful in preventing grossly excessive spending by regulated companies. As well, even when an historic test year is used without careful review of costs, it tends to provide an incentive for management to operate efficiently, because cost increases are not passed along to customers for at least a year or two. During this lag period, the full burden of any unnecessary costs is borne by stockholders. As well, the benefit of any cost savings flows into retained earnings during the period between rate cases – which can potentially be 5 or more years, thereby creating a strong incentive for management to operate efficiently.

Most thoughtful observers will concede that under traditional rate base regulation the incentives to control costs are not quite as strong as what occurs in highly competitive markets, and that this constitutes one of the weaknesses with traditional regulation. Nevertheless, there is no evidence that this is a fatal flaw, or that utilities have been grossly inefficient or wasteful in the way they operate. To the contrary, any weakness in the incentive for cost minimization tends to be mitigated by several factors, including the vigilance of regulators, who attempt to detect and disallow excessive or imprudent costs.

But, in evaluating the overall impact of regulation, it is clear that the beneficial effects of "regulatory lag" are a very important part of the overall picture. During the interim period between rate cases, prices are not tied to costs, and thus the normal inverse relationship between costs and profits tends to prevail. The lag between the time a firm incurs costs and the time those costs can potentially affect its prices is typically at least a few years, and it can sometimes be a decade or more. In that situation, a firm operating under rate base regulation has essentially the same incentives for cost minimization that would exist under price cap regulation.

The longer the period between rate cases, the greater the "regulatory lag" and the greater the reward from the increased profits that will result from successful efforts to cut costs and increase productivity. At the extreme, if the lag period between rate cases is extremely long, the incentive structure is nearly the same as if the firm were unregulated.

This discussion of regulatory lag and the incentives for cost cutting and efficiency is important to the resolution of this case, because there are aspects of the Company's proposals which tend to undermine the incentives that normally exist under rate base regulation. As well, if the Commission decides to deviate from a strict historical test year, I believe it should strive for an approach that retains strong incentives for efficiency, and which reduces the need for the Company to file a constant stream of frequent rate cases – because a series of back-to-back rate cases will undermine the incentives for management to keep costs tightly under control.

Q. Do you have any specific recommendations, in the event the Commission concludes that attrition relief should be provided?

A. Yes. As shown on Lines 7-9 of Page 1 of Schedule BJ-14, the Company's attrition rate has been fairly mild, averaging about .55% to .75% per year relative to revenues. If the Commission wanted to provide compensation for 18 months of attrition past the test year, this would suggest an increase in rates above the level justified by the historical test year of approximately 1.36 to 1.86%, after application of the Gross Revenue Conversion Factor of 1.6491.

If the Commission were to conclude that a larger amount of attrition compensation would be appropriate, in order to strengthen the Company's financial position to an even greater degree, I would recommend any such additional attrition compensation be phased in after the conclusion of this case. For instance, a surcharge could be approved in the final order in this proceeding which would not go into effect until 6 months or a year after the initial rate increase. A phased-in surcharge would provide additional support for the Company's credit metrics, while minimizing the immediate impact on customers. This would provide the Company with additional rate relief based on the evidence in this case without eliminating the beneficial efficiency incentives that result from regulatory lag.

Of course, a surcharge of this type would not preclude the Company from filing future rate cases if management truly believes it is not being sufficiently compensated for the attrition, or other unexpected extenuating circumstances arise in the future. However, it would provide a degree of cash flow improvement between rate filings, helping to preserve APS' financial metric and bond ratings, and it would reduce the incentive for APS to immediately file another rate case. As well, a surcharge would reduce the pressure on the Commission to rapidly process any such future rate case.

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816
TABLE OF CONTENTS TO BJ SCHEDULES

SCHEDULE

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
ACC JURISDICTIONAL REVENUE REQUIREMENTS
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-1

LINE NO.	DESCRIPTION	(A) ACC JURIS. RUCO ORIGINAL COST	(B) ACC JURIS. RUCO RCND	(C) RUCO FAIR VALUE
1	ADJUSTED RATE BASE	$4,935,675	$9,642,379	$7,289,027
2	OPERATING INCOME	285,103	285,103	285,103
3	CURRENT RATE OF RETURN (L2 / L1)	5.78%	2.96%	3.91%
4	REQUIRED OPERATING INCOME (L5 * L1)	380,047	380,047	380,047
5	REQUIRED RATE OF RETURN	7.70%	3.94%	5.21%
6	OPERATING INCOME DEFICIENCY (L4 - L2)	94,944	94,944	94,944
7	GROSS REVENUE CONVERSION FACTOR			1.6491
8	BASE RATE INCREASE (L6 * L7)			$156,572
9	CURRENT RETAIL REVENUES T/Y ADJUSTED*			$2,748,697
10	PERCENTAGE INCREASE IN BASE RATES (L8 / L9)			5.70%
11	OFFSETTING REDUCTION IN PSA RATE			$169,977
12	NET (L8 – L11)			$(13,405)

REFERENCES:
COLUMN (A): RUCO SCHEDULES BJ-2, BJ-7, BJ-12, COMPANY SCHEDULE C-3
COLUMN (B): RUCO SCHEDULES BJ-5, BJ-7, COMPANY SCHEDULE C-3
COLUMN (C): JOHNSON TESTIMONY, RUCO SCHEDULES BJ-7, COMPANY SCHEDULES A-1, C-3

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
ORIGINAL COST RATE BASE
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-2

LINE NO.	DESCRIPTION	(A) AS FILED UNADJUSTED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO AS ADJUSTED TOTAL COMPANY	(D) RUCO AS ADJUSTED ACC JURISDICTION
1	GROSS UTILITY PLANT IN SERVICE	$11,925,725	$(13,833)	$11,911,892	$10,322,659
2	Less: Accumulated depreciation & amortization	4,637,472	2,649	4,640,121	$4,092,257
3	NET UTILITY PLANT IN SERVICE	**$7,288,253**	**$(11,184)**	**$7,277,069**	**$6,230,402**
	DEDUCTIONS:				
4	Deferred income taxes	$1,206,568	$-	$1,206,568	$1,018,730
5	Investment tax credits	731	-	731	718
6	Customer advances for construction (c)	94,801	-	94,801	94,801
7	Customer deposits	71,311	-	71,311	71,311
8	Pension and other postretirement liabilities	434,025	-	434,025	407,675
9	Liability for asset retirement (c)	281,903	-	281,903	276,913
10	Other deferred credits	158,294	-	158,294	151,078
11	Unamortized gain-sale of utility plant (c)	36,606	-	36,606	35,958
12	Regulatory liabilities	225,479	-	225,479	219,956
13	TOTAL DEDUCTIONS	**$2,509,718**	**$(1,120)**	**$2,508,598**	**$2,276,040**
	ADDITIONS:				
14	Regulatory assets	$426,987	$-	$426,987	$398,567
15	Other deferred debits	63,879	-	63,879	60,303
16	Decommissioning trust accounts (c)	379,347	-	379,347	370,098
17	Allowance for working capital (d)	159,052	4,078	163,130	152,345
18	TOTAL ADDITIONS	**$1,029,265**	**$4,078**	**$1,033,343**	**$981,313**
19	TOTAL RATE BASE	**$5,807,800**	**$(5,986)**	**$5,801,814**	**$4,935,675**

REFERENCES:
COLUMN (A): RUCO SCHEDULE BJ-3
COLUMN (B): RUCO SCHEDULE BJ-3
COLUMN (C): RUCO SCHEDULE BJ-3
COLUMN (D): RUCO SCHEDULE BJ-4

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
ORIGINAL COST RATE BASE ADJUSTMENTS: TOTAL COMPANY
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-3

LINE NO.	DESCRIPTION	(A) ORIGINAL COST TOTAL COMPANY	(B) West Phoenix Unit 4	(C) Working Capital	(D) RUCO ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$11,925,725	$(13,833)		$11,911,892
2	Less: Accumulated depreciation & amortization	4,637,472	2,649		4,640,121
3	NET UTILITY PLANT IN SERVICE	**$7,288,253**	**$(11,184)**		**$7,277,069**
	DEDUCTIONS:				
4	Deferred income taxes	1,206,568			$1,206,568
5	Investment tax credits	731			731
6	Customer advances for construction (c)	94,801			94,801
7	Customer deposits	71,311			71,311
8	Pension and other postretirement liabilities	434,025			434,025
9	Liability for asset retirement (c)	281,903			281,903
10	Other deferred credits	158,294			158,294
11	Unamortized gain-sale of utility plant (c)	36,606			36,606
12	Regulatory liabilities	225,479			225,479
13	TOTAL DEDUCTIONS	**$2,509,718**	**$(1,120)**		**$2,508,598**
	ADDITIONS:				
14	Regulatory assets	$426,987			$426,987
15	Other deferred debits	63,879			63,879
16	Decommissioning trust accounts (c)	379,347			379,347
17	Allowance for working capital (d)	159,052		4,078	163,130
18	TOTAL ADDITIONS	**$1,029,265**	**$-**	**$4,078**	**$1,033,343**
19	TOTAL RATE BASE	**$5,807,800**	**$(10,064)**	**$4,078**	**$5,801,814**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1 (1)
COLUMN (B): COMPANY SCHEDULE B-2
COLUMN (C): COMPANY RESPONSE TO STAFF DISCOVERY 13.1
COLUMN (D): SUM OF COLUMNS A-C

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
ORIGINAL COST RATE BASE ADJUSTMENTS: ACC
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-4

LINE NO.	DESCRIPTION	(A) ORIGINAL COST ACC JURISDICTIONAL	(B) West Phoenix Unit 4	(C) Working Capital	(D) RUCO ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$10,336,247	$(13,588)		$10,322,659
2	Less: Accumulated depreciation & amortization	4,094,859	(2,602)		4,092,257
3	NET UTILITY PLANT IN SERVICE	**$6,241,388**	**$(10,986)**		**$6,230,402**
	DEDUCTIONS:				
4	Deferred income taxes	1,018,730			$1,018,730
5	Investment tax credits	718			718
6	Customer advances for construction (c)	94,801			94,801
7	Customer deposits	71,311			71,311
8	Pension and other postretirement liabilities	407,675			407,675
9	Liability for asset retirement (c)	276,913			276,913
10	Other deferred credits	151,078			151,078
11	Unamortized gain-sale of utility plant (c)	35,958			35,958
12	Regulatory liabilities	219,956			219,956
13	TOTAL DEDUCTIONS	**$2,277,140**	**$(1,100)**		**$2,276,040**
	ADDITIONS:				
14	Regulatory assets	$398,567			$398,567
15	Other deferred debits	60,303			60,303
16	Decommissioning trust accounts (c)	370,098			370,098
17	Allowance for working capital (d)	148,267		4,078	152,345
18	TOTAL ADDITIONS	**$977,235**	**$-**	**$4,078**	**$981,313**
19	TOTAL RATE BASE	**$4,941,483**	**$(9,886)**	**$4,078**	**$4,935,675**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1 (1)
COLUMN (B): COMPANY SCHEDULE B-2
COLUMN (C): COMPANY RESPONSE TO STAFF DISCOVERY 13.1
COLUMN (D): SUM OF COLUMNS A-C

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
RCND RATE BASE
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-5

LINE NO.	DESCRIPTION	(A) AS FILED RCND ACC JURISDICTIONAL	(B) RUCO ADJUSTMENTS ACC JURISDICTION	(C) RUCO AS ADJUSTED ACC JURISDICTION
1	GROSS UTILITY PLANT IN SERVICE	$18,542,222	$(13,588)	$18,528,634
2	Less: Accumulated depreciation & amortization	7,594,130	2,602	7,596,732
3	NET UTILITY PLANT IN SERVICE	**$10,948,092**	**$(10,986)**	**$10,937,106**
	DEDUCTIONS:			
4	Deferred income taxes	$1,018,730	$-	$1,018,730
5	Investment tax credits	718	-	718
6	Customer advances for construction (c)	94,801	-	94,801
7	Customer deposits	71,311	-	71,311
8	Pension and other postretirement liabilities	407,675	-	407,675
9	Liability for asset retirement (c)	276,913	-	276,913
10	Other deferred credits	151,078	-	151,078
11	Unamortized gain-sale of utility plant (c)	35,958	-	35,958
12	Regulatory liabilities	219,956	-	219,956
13	TOTAL DEDUCTIONS	**$2,277,140**	**$1,100**	**$2,278,240**
	ADDITIONS:			
14	Regulatory assets	$398,567	$-	$398,567
15	Other deferred debits	60,303	-	60,303
16	Decommissioning trust accounts (c)	370,098	-	370,098
17	Allowance for working capital (d)	148,267	4,078	152,345
18	TOTAL ADDITIONS	**$977,235**	**$4,078**	**$981,313**
19	TOTAL RATE BASE	**$9,648,187**	**$(5,808)**	**$9,642,379**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1 (2)
COLUMN (B): RUCO SCHEDULE BJ-6
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
RCND RATE BASE ADJUSTMENTS: ACC
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-6

LINE NO.	DESCRIPTION	(A) RCND ACC JURISDICTIONAL	(B) West Phoenix Unit 4	(C) Working Capital	(D) RUCO AS ADJUSTED ACC JURISDICTION
1	GROSS UTILITY PLANT IN SERVICE	$18,542,222	$(13,588)	$-	$18,528,634
2	Less: Accumulated depreciation & amortization	7,594,130	2,602		7,596,732
3	NET UTILITY PLANT IN SERVICE	**$10,948,092**	**$(10,986)**	**$-**	**$10,937,106**
	DEDUCTIONS:				
4	Deferred income taxes	1,018,730		$-	$1,018,730
5	Investment tax credits	718			718
6	Customer advances for construction (c)	94,801			94,801
7	Customer deposits	71,311			71,311
8	Pension and other postretirement liabilities	407,675			407,675
9	Liability for asset retirement (c)	276,913			276,913
10	Other deferred credits	151,078			151,078
11	Unamortized gain-sale of utility plant (c)	35,958			35,958
12	Regulatory liabilities	219,956			219,956
13	TOTAL DEDUCTIONS	**$2,277,140**	1,100	**$-**	**$2,278,240**
	ADDITIONS:				
14	Regulatory assets	398,567	$-		$398,567
15	Other deferred debits	60,303			60,303
16	Decommissioning trust accounts (c)	370,098			370,098
17	Allowance for working capital (d)	148,267		4,078	152,345
18	TOTAL ADDITIONS	**$977,235**	**$-**	**$4,078**	**$981,313**
19	TOTAL RATE BASE	**$9,648,187**	**$(9,886)**	**$4,078**	**$9,642,379**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1 (2)
COLUMN (B): COMPANY SCHEDULE B-2
COLUMN (C): COMPANY RESPONSE TO STAFF DISCOVERY 13.1
COLUMN (D): SUM OF COLUMNS A-C

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
OPERATING INCOME
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-7

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO AS ADJUSTED TOTAL COMPANY	(D) AS FILED ACC JURISDICTION	(E) RUCO ADJUSTMENTS ACC JURISDICTION	(F) RUCO AS ADJUSTED ACC JURISDICTION
1	ELECTRIC OPERATING REVENUES						
	Revenues from Base Rates	$2,562,202	$144,737	$2,706,939	$2,509,499	$144,737	$2,654,236
	Revenues from Surcharges	251,213	(251,213)	-	251,213	(251,213)	-
	Other Electric Revenues	122,862	-	122,862	94,461	-	94,461
	Total Electric Operating Revenues	**$2,936,277**	**$(106,476)**	**$2,829,801**	**$2,855,173**	**$(106,476)**	**$2,748,697**
	OPERATING EXPENSES:						
2	PURCHASED POWER AND FUEL	$1,151,392	$81,496	$1,232,888	1,118,859	81,361	1,200,220
3	OPERATIONS AND MAINTENANCE	710,077	(31,611)	678,466	766,438	(30,813)	735,625
4	DEPRECIATION AND AMORTIZATION	365,430	1,286	366,716	328,872	(1,343)	327,529
5	INCOME TAXES	155,735	(59,840)	95,895	146,531	(60,400)	86,131
6	OTHER TAXES	127,648	4,248	131,896	110,411	3,678	114,089
7	TOTAL	**$2,510,282**	**$(4,420)**	**$2,505,862**	**$2,471,111**	**$(7,517)**	**$2,463,594**
8	OPERATING INCOME	**$425,995**	**$(102,056)**	**$323,939**	**$384,062**	**$(98,959)**	**$285,103**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C-1 (1)
COLUMN (B): RUCO SCHEDULE BJ-8
COLUMN (C): COLUMNS A + B
COLUMN (D): COMPANY SCHEDULE C-1 (2)
COLUMN (E): RUCO SCHEDULE BJ-9
COLUMN (F): COLUMNS D + E

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
OPERATING INCOME ADJUSTMENTS: TOTAL COMPANY
(000's)

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	(B) Base Fuel and Purchase Power	(C) Test Year PSA Revenue and Deferred Amort	(D) Test Year Retail Deferred Fuel Mark-to-Market	(E) Normalize Non-Nuclear Maintenance	(F) Normalize Nuclear Maintenance	(G) Normalize Weather Conditions	(H) Annualize Customer Levels	(I) Annualize Spent Fuel Storage Costs
1	ELECTRIC OPERATING REVENUES									
	Revenues from Base Rates	$2,562,202						(39,380)	41,846	
	Revenues from Surcharges	251,213		(227,430)						
	Other Electric Revenues	122,862								
	Total Electric Operating Revenues	$2,936,277		$(227,430)				$(39,380)	$41,846	
	OPERATING EXPENSES:									
2	PURCHASED POWER AND FUEL	$1,151,392	129,649	(240,739)	189,059			(15,298)	16,971	1,289
3	OPERATIONS AND MAINTENANCE	710,077				(3,290)	(5,556)	(2,120)	2,352	
4	DEPRECIATION AND AMORTIZATION	365,430								
5	INCOME TAXES	155,735	(51,030)	5,238	(74,414)	1,295	2,187	(8,644)	8,865	(507)
6	OTHER TAXES	127,648								
7	TOTAL	**$2,510,282**	**$78,619**	**$(235,501)**	**$114,645**	**$(1,995)**	**$(3,369)**	**$(26,062)**	**$28,188**	**$782**
8	OPERATING INCOME	**$425,995**	**$(78,619)**	**$8,071**	**$(114,645)**	**$1,995**	**$3,369**	**$(13,318)**	**$13,658**	**$(782)**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
SUMMARY OF OPERATING ADJUSTMENTS (000'S)
(000's)

LINE NO.	DESCRIPTION	(J) Annualize Four Corners Coal Rec. Costs	(K) Annualize Bark Beetle Costs	(L) Annualize Depreciation and Amort.	(M) Remove Test Year Surcharges	(N) Annualize Sundance Overhaul	(O) West Phoenix Unit 4 Reg. Disallow	(P) Interest Expense Cust. Deposits	(Q) Depreciation Expense 2007 Study	(R) Annualize Payroll
1	ELECTRIC OPERATING REVENUES									
	Revenues from Base Rates				$3,000					
	Revenues from Surcharges				(23,783)					
	Other Electric Revenues				-					
	Total Electric Operating Revenues				**$(20,783)**					
	OPERATING EXPENSES:									
2	PURCHASED POWER AND FUEL	334								
3	OPERATIONS AND MAINTENANCE		1,918		(19,347)	805		2,261		7,637
4	DEPRECIATION AND AMORTIZATION			10,691			(329)		(9,076)	
5	INCOME TAXES	(131)	(755)	(4,208)	(565)	(317)	235	(890)	3,572	(3,006)
6	OTHER TAXES									
7	TOTAL	**$203**	**$1,163**	**$6,483**	**$(19,912)**	**$488**	**$(94)**	**$1,371**	**$(5,504)**	**$4,631**
8	OPERATING INCOME	**$(203)**	**$(1,163)**	**$(6,483)**	**$(871)**	**$(488)**	**$94**	**$(1,371)**	**$5,504**	**$(4,631)**

REFERENCES:
COLUMN (J): COMPANY SCHEDULE C-2
COLUMN (K): COMPANY SCHEDULE C-2
COLUMN (L): COMPANY SCHEDULE C-2
COLUMN (M): COMPANY SCHEDULE C-2
COLUMN (N): COMPANY SCHEDULE C-2
COLUMN (O): COMPANY SCHEDULE C-2
COLUMN (P): COMPANY SCHEDULE C-2
COLUMN (Q): COMPANY SCHEDULE C-2
COLUMN (R): RUCO SCHEDULE BJ-13

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
SUMMARY OF OPERATING ADJUSTMENTS (000'S)
(000's)

LINE NO.	DESCRIPTION	(S) Synchronize Income Taxes	(T) Annualize Property Tax	(U) Annualize Navajo Coal Rec.	(V) Normalize Customer Bad Debt	(W) Miscellaneous Out-of-Period Adjustments	(X) SurePay/ AutoPay Discount	(Y) Annualize Rates	(Z) SERP	(AA) RUCO ADJUSTED TOTAL COMPANY
1	ELECTRIC OPERATING REVENUES									
	Revenues from Base Rates						(769)	140,040		2,706,939
	Revenues from Surcharges						-	-		-
	Other Electric Revenues						-	-		122,862
	Total Electric Operating Revenues						$(769)	$140,040		$2,829,801
	OPERATING EXPENSES:									
2	PURCHASED POWER AND FUEL			231						1,232,888
3	OPERATIONS AND MAINTENANCE				979	(4,268)			(5,345)	686,103
4	DEPRECIATION AND AMORTIZATION									366,716
5	INCOME TAXES	5,880	(1,672)	(91)	(385)	1,680	(303)	55,120		92,889
6	OTHER TAXES		4,248							131,896
7	TOTAL	**$5,880**	**$2,576**	**$140**	**$594**	**$(2,588)**	**$(303)**	**$55,120**	**$(5,345)**	**$2,510,493**
8	OPERATING INCOME	**$(5,880)**	**$(2,576)**	**$(140)**	**$(594)**	**$2,588**	**$(466)**	**$84,920**	**$5,345**	**$319,308**

REFERENCES:
COLUMN (S): RUCO SCHEDULE BJ-12
COLUMN (T): RUCO SCHEDULE BJ-10; COMPANY SCHEDULE C-2
COLUMN (U): COMPANY SCHEDULE C-2
COLUMN (V): COMPANY SCHEDULE C-2
COLUMN (W): COMPANY SCHEDULE C-2
COLUMN (X): COMPANY SCHEDULE C-2
COLUMN (Y): COMPANY SCHEDULE C-2
COLUMN (Z): COMPANY RESPONSE TO STAFF DR 13.11
COLUMN (AA): SUM COLUMNS A – Z

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
OPERATING INCOME ADJUSTMENTS: ACC
(000's)

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	(B) Base Fuel and Purchase Power	(C) PSA Revenue and Deferred Amortization	(D) Retail Deferred Fuel Mark-to-Market	(E) Normalize Non-Nuclear Maintenance	(F) Normalize Nuclear Maintenance	(G) Normalize Weather Conditions	(H) Annualize Customer Levels	(I) Annualize Spent Fuel Storage Costs
	ELECTRIC OPERATING REVENUES									
1	Revenues from Base Rates	$2,509,499						(39,380)	41,846	
2	Revenues from Surcharges	251,213		(227,430)						
3	Other Electric Revenues	94,461								
4	Total Electric Operating Revenues	$2,855,173		$(227,430)				$(39,380)	$41,846	
	OPERATING EXPENSES:									
5	PURCHASED POWER AND FUEL	$1,118,859	129,649	(240,739)	188,969			(15,298)	16,971	1,258
6	OPERATIONS AND MAINTENANCE	766,438				(3,210)	(5,421)	(2,120)	2,352	
7	DEPRECIATION AND AMORTIZATION	328,872								
8	INCOME TAXES	146,531	(51,030)	5,238	(74,378)	1,263	2,134	(8,644)	8,865	(495)
9	OTHER TAXES	110,411								
10	TOTAL	**$2,471,111**	**$78,619**	**$(235,501)**	**$114,591**	**$(1,947)**	**$(3,287)**	**$(26,062)**	**$28,188**	**$763**
11	OPERATING INCOME	**$384,062**	**$(78,619)**	**$8,071**	**$(114,591)**	**$1,947**	**$3,287**	**$(13,318)**	**$13,658**	**$(763)**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C-1 (1)
COLUMN (B): COMPANY SCHEDULE C-2
COLUMN (C): COMPANY SCHEDULE C-2
COLUMN (D): COMPANY SCHEDULE C-2
COLUMN (E): COMPANY SCHEDULE C-2
COLUMN (F): COMPANY SCHEDULE C-2
COLUMN (G): COMPANY SCHEDULE C-2
COLUMN (H): COMPANY SCHEDULE C-2
COLUMN (I): COMPANY SCHEDULE C-2

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
SUMMARY OF OPERATING ADJUSTMENTS (000'S)
(000's)

LINE NO.	DESCRIPTION	(J) Annualize Four Corners Coal Rec. Costs	(K) Annualize Bark Beetle Costs	(L) Annualize Depreciation and Amort.	(M) Remove Test Year Surcharges	(N) Annualize Sundance Overhaul	(O) West Phoenix Unit 4 Reg. Disallow	(P) Interest Expense Cust. Deposits	(Q) Depreciation Expense 2007 Study	(R) Annualize Payroll
	ELECTRIC OPERATING REVENUES									
1	Revenues from Base Rates				$3,000					
2	Revenues from Surcharges				(23,783)					
3	Other Electric Revenues				-					
4	Total Electric Operating Revenues				$(20,783)					
	OPERATING EXPENSES:									
5	PURCHASED POWER AND FUEL	326								
6	OPERATIONS AND MAINTENANCE		1,918		(19,347)	785		2,261		7,173
7	DEPRECIATION AND AMORTIZATION			8,610			(323)		(9,630)	
8	INCOME TAXES	(128)	(755)	(3,389)	(565)	(309)	231	(890)	3,790	(2,823)
9	OTHER TAXES									
10	TOTAL	**$198**	**$1,163**	**$5,221**	**$(19,912)**	**$476**	**$(92)**	**$1,371**	**$(5,840)**	**$4,350**
11	OPERATING INCOME	**$(198)**	**$(1,163)**	**$(5,221)**	**$(871)**	**$(476)**	**$92**	**$(1,371)**	**$5,840**	**$(4,350)**

REFERENCES:
COLUMN (J): COMPANY SCHEDULE C-2
COLUMN (K): COMPANY SCHEDULE C-2
COLUMN (L): COMPANY SCHEDULE C-2
COLUMN (M): COMPANY SCHEDULE C-2
COLUMN (N): COMPANY SCHEDULE C-2
COLUMN (O): COMPANY SCHEDULE C-2
COLUMN (P): COMPANY SCHEDULE C-2
COLUMN (Q): COMPANY SCHEDULE C-2
COLUMN (R): RUCO SCHEDULE BJ-13

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
SUMMARY OF OPERATING ADJUSTMENTS (000'S)
(000's)

LINE NO.	DESCRIPTION	(S) Synchronize Income Taxes	(T) Annualize Property Tax	(U) Annualize Navajo Coal Rec.	(V) Normalize Customer Bad Debt	(W) Miscellaneous Out-of-Period Adjustments	(X) SurePay/ AutoPay Discount	(Y) Annualize Rates	(Z) SERP	(AA) RUCO ADJUSTED TOTAL COMPANY
	ELECTRIC OPERATING REVENUES									
1	Revenues from Base Rates						$(769)	$140,040		$2,654,236
2	Revenues from Surcharges						-	-		-
3	Other Electric Revenues						-	-		94,461
4	Total Electric Operating Revenues						$(769)	$140,040		$2,748,697
	OPERATING EXPENSES:									
5	PURCHASED POWER AND FUEL			225						$1,200,220
6	OPERATIONS AND MAINTENANCE				978	(3,904)			(5,105)	$742,798
7	DEPRECIATION AND AMORTIZATION									$327,529
8	INCOME TAXES	4,230	(1,447)	(89)	(385)	1,537	(303)	55,120		$83,308
9	OTHER TAXES		3,678							114,089
10	TOTAL	**$4,230**	**$2,230**	**$136**	**$593**	**$(2,367)**	**$(303)**	**$55,120**	**$(5,105)**	**$2,467,944**
11	OPERATING INCOME	**$(4,230)**	**$(2,230)**	**$(136)**	**$(593)**	**$2,367**	**$(466)**	**$84,920**	**$5,105**	**$280,753**

REFERENCES:
COLUMN (S): RUCO SCHEDULE BJ-12
COLUMN (T): RUCO SCHEDULE BJ-10; COMPANY SCHEDULE C-2
COLUMN (U): COMPANY SCHEDULE C-2
COLUMN (V): COMPANY SCHEDULE C-2
COLUMN (W): COMPANY SCHEDULE C-2
COLUMN (X): COMPANY SCHEDULE C-2
COLUMN (Y): COMPANY SCHEDULE C-2
COLUMN (Z): COMPANY RESPONSE TO STAFF DR 13.11
COLUMN (AA): SUM COLUMNS A – Z

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
PROPERTY TAX ADJUSTMENT
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-10

LINE NO.	DESCRIPTION	(A) AMOUNT
1	12/31/2007 UTILITY PLANT – NET	$7,992,847
2	12/31/2006 UTILITY PLANT – NET	7,439,999
3	2007 AVERAGE UTILITY PLANT – NET	7,716,423
4	PERCENT INCREASE FROM 2007 AVERAGE TO 2007 END OF YEAR	3.58%
5	2007 ARIZONA PROPERTY TAXES	118,596
6	ESTIMATED 2007 PROPERTY TAXES BASED ON END OF YEAR PLANT VALUES	122,845
7	PRO FORMA PROPERTY TAX ADJUSTMENT	4,248
8	ACC JURISDICTIONAL FACTOR	86.56%
9	ACC PRO FORMA PROPERTY TAX ADJUSTMENT	3,678

REFERENCE
COMPANY SCHEDULES E-1, C-2; COMPANY WORKPAPER JCL WP26, TAB A20
LINE 1: COMPANY SCHEDULE E-1
LINE 2: COMPANY SCHEDULE E-1
LINE 3: (LINE 1 + LINE 2) / 2
LINE 4: (LINE 1 – LINE 3) / LINE 3
LINE 5: COMPANY WORKPAPER JCL WP26, TAB A20
LINE 6: LINE 5 * (1 + LINE 4)
LINE 7: (LINE 6 – LINE 5)
LINE 8: COMPANY SCHEDULE C-2, COLUMN 26 (13038 / 15062)
LINE 9: LINE 8 * LINE 7

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
RUCO COST OF CAPITAL

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-11

LINE NO.	TYPE OF CAPITAL	(A) PERCENT	(B) COST RATE	(C) WEIGHTED AVG. COST RATE
1	COMMON EQUITY	53.79%	9.60%	5.16%
2	TOTAL DEBT	46.21%	5.48%	2.53%
3	TOTALS	100.00%		7.70%

REFERENCES:
COLUMN (A): RUCO TESTIMONY - RIGSBY
COLUMN (B): RUCO TESTIMONY - RIGSBY
COLUMN (C): COLUMNS A x B

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
NCOME TAX SYNCHRONIZATION ADJUSTMENT
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-12

LINE NO.	DESCRIPTION	(A) TOTAL COMPANY AMOUNT	(B) ACC JURISDICTIONAL AMOUNT
	FEDERAL INCOME TAXES:		
1	OPERATING INCOME BEFORE INCOME TAXES	$581,730	$530,593
	LESS:		
2	ARIZONA STATE TAX (L11)	29,176	27,216
3	INTEREST EXPENSE (L17)	146,920	124,986
4	FEDERAL TAXABLE INCOME (L1 – L2 – L3)	405,634	378,390
5	FEDERAL INCOME TAX RATE	32.65%	32.65%
6	FEDERAL INCOME TAX EXPENSE (L4 * L5)	132,440	123,544
	STATE INCOME TAXES:		
7	OPERATING INCOME BEFORE INCOME TAXES (L1)	581,730	530,593
	LESS:		
8	INTEREST EXPENSE (L17)	146,920	124,986
9	STATE TAXABLE INCOME (L7 – L8)	434,810	405,607
10	STATE TAX RATE	6.71%	6.71%
11	STATE INCOME TAX EXPENSE (L9 * L10)	29,176	27,216
12	TOTAL INCOME TAXES (L6 + L11)	161,615	150,761
13	INCOME TAXES PER COMPANY	155,735	146,531
14	ADJUSTMENT	$5,880	$4,230
	SYCHRONIZE INTEREST TO RATE BASE:		
15	ADJUSTED RATE BASE	$5,801,814	$4,935,675
16	WEIGHTED COST OF DEBT	2.53%	2.53%
17	INTEREST EXPENSE	$146,920	$124,986

REFERENCES:
LINE 1: RUCO SCHEDULE BJ-4
LINE 5: COMPANY SCHEDULE C-3
LINE 10: COMPANY SCHEDULE C-3
LINE 13: RUCO SCHEDULE BJ-4
LINE 14: LINE 12 – LINE 13

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
PAYROLL ADJUSTMENT
(000's)

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-13

			As Filed Annualize Payroll		Adjusted Annualize Payroll	
LINE NO.	DESCRIPTION		(A) Total Co.	(B) ACC	(C) Total Co.	(D) ACC
	OTHER OPERATING EXPENSES					
1	Operations Excluding Fuel Expense		15,458	14,520	5,665	5,321
2	Maintenance		5,380	5,053	1,972	1,852
3	SUBTOTAL		20,838	19,573	7,637	7,173
4	OPERATING INCOME BEFORE INCOME TAX		(20,838)	(19,573)	(7,637)	(7,173)
	INTEREST EXPENSE		-	-	-	-
5	TAXABLE INCOME		(20,838)	(19,573)	(7,637)	(7,173)
6	CURRENT INCOME TAX RATE	39.36%	(8,202)	(7,704)	(3,006)	(2,823)
7	OPERATING INCOME		$(12,636)	$(11,869)	$(4,631)	$(4,350)

REFERENCES:
COLUMN (A): APS SCHEDULE C-2
COLUMN (B): APS SCHEDULE C-2
COLUMN (C): APS RESPONSE TO RUCO DR 10.4
COLUMN (D) LINES 1 AND 2: (COLUMN B/COLUMN A) * COLUMN C

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
ATTRITION ANALYSIS
(000's)

LINE NO.	DESCRIPTION	2005	2006	2007	2008	2009	2010
	ATTRITION CALCULATIONS						
1	Operating Income	401,200	425,900	411,000	430,574	405,825	416,283
2	Net Utility Plant	7,140,685	7,439,999	7,992,847	8,635,000	9,309,000	9,835,000
3	NOI/Net Plant	5.6%	5.7%	5.1%	5.0%	4.4%	4.2%
4	Attrition		-0.1%	0.6%	0.2%	0.6%	0.1%
5	Attrition in Dollars		-7,566	43,328	12,446	54,132	11,806
6	Attrition as % of Revenues		-0.3%	1.5%	0.4%	1.7%	0.4%
	Averages:		% of Net Plant		Dollars/Year		% of Revenue
7	2005 – 2007		0.24%		17,881		0.55%
8	2007 – 2010		0.30%		26,128		0.83%
9	2005 – 2010		0.28%		22,829		0.75%

REFERENCE:
LINE 1: COMPANY RESPONSE TO RUCO DR 8.4; COMPANY SCHEDULE A-2
LINE 2: COMPANY RESPONSE TO RUCO DR 9.1; COMPANY SCHEDULE E-1
LINE 3: LINE 1 / LINE 2
LINE 4: LINE 3 PRECEDING YEAR – LINE 3 CURRENT YEAR
LINE 5: LINE 4 * NET UTILITY PLANT PRECEDING YEAR
LINE 6: LINE 5 * PAGE 3, LINE 1
LINES 7-9: AVERAGES OF LINE 4, LINE 5 AND LINE 6.

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
ATTRITION ANALYSIS
(000's)

LINE NO.	DESCRIPTION	2005	2006	2007	2008	2009	2010
	GROSS REVENUES						
1	From A-2	2,270,793	2,658,513	2,936,277	3,132,395	3,131,036	3,260,695
2	From Ruco 8 3	2,270,800	2,658,500	2,936,300			
3	Adjustment	13,100	5,500	-41,800			
4	Adjusted Data	2,283,900	2,664,000	2,894,500	3,132,395	3,131,036	3,260,695
5	Adjustment %	0.58%	0.21%	-1.42%			
6	MWH	26,477,551	27,970,397	29,171,321	29,034,429	29,550,350	30,114,513
7	Adjustment %	0.58%	0.21%	-1.42%			
8	Adjusted Data	26,630,297	28,028,263	28,756,050	29,034,429	29,550,350	30,114,513

REFERENCE:
LINE 1: COMPANY SCHEDULE A-2
LINE 2: COMPANY RESPONSE TO RUCO DR 8.3
LINE 3: COMPANY RESPONSE TO RUCO DR 8.3
LINE 4: LINE 2 + LINE 3
LINE 5: LINE 3 / LINE 2
LINE 6: EWEN WORKPAPER PME_WP02_APS08650.xls
LINE 7: LINE 5
LINE 8: LINE 6 * (1 + LINE 7)

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
ATTRITION ANALYSIS
(000's)

LINE NO.	DESCRIPTION	2005	2006	2007	2008	2009	2010	Average
	REVENUE DATA							
1	Gross Revenues	2,608,800	2,738,400	2,810,800	3,132,395	3,131,036	3,260,695	
2	% Change Yr over Yr		5.0%	2.6%	11.4%	0.0%	4.1%	4.63%
3	Retail Customers	1,007,640	1,051,895	1,086,328	1,102,326	1,118,332	1,141,443	
4	% Change Yr over Yr		4.4%	3.3%	1.5%	1.5%	2.1%	2.53%
5	Retail MWH Sales	26,630,297	28,028,263	28,756,050	29,034,429	29,550,350	30,114,513	
6	% Change Yr over Yr		5.2%	2.6%	1.0%	1.8%	1.9%	2.50%
7	Revenues per Retail Customer	2,589	2,603	2,587	2,842	2,800	2,857	
8	% Change Yr over Yr		0.6%	-0.6%	9.8%	-1.5%	2.0%	2.06%
9	MWH Sales per Retail Customer	26.4	26.6	26.5	26.3	26.4	26.4	
10	% Change Yr over Yr		0.8%	-0.7%	-0.5%	0.3%	-0.2%	-0.03%
11	Revenues per kwh	0.098	0.098	0.098	0.108	0.106	0.108	

REFERENCE:
LINE 1: COMPANY RESPONSE TO RUCO DR 8.4; COMPANY SCHEDULE A-2
LINE 3: EWEN WORKPAPER PME_WP02_APS08650.xls
LINE 5: PAGE 2, LINE 8
LINE 7: (LINE 1 / LINE 3) * 1000
LINE 9: LINE 5 / LINE 3
LINE 11: LINE 1 / LINE 5

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
ATTRITION ANALYSIS
(000's)

LINE NO.	DESCRIPTION	2005	2006	2007	2008	2009	2010	Average
	EXPENSE DATA							
1	Revenue Deductions & Operating Expense:	2,207,600	2,312,500	2,399,800	2,701,821	2,725,211	2,844,412	
2	% Change Yr over Yr		4.8%	3.8%	12.6%	0.9%	4.4%	5.27%
3	Net Utility Plant	7,140,685	7,439,999	7,992,847	8,635,000	9,309,000	9,835,000	
4	% Change Yr over Yr		4.2%	7.4%	8.0%	7.8%	5.7%	6.62%
5	Net Utility Plant per Retail Customer	7,087	7,073	7,358	7,833	8,324	8,616	
6	% Change Yr over Yr		-0.2%	4.0%	6.5%	6.3%	3.5%	4.01%
	INCOME DATA							
7	Operating Income	401,200	425,900	411,000	430,574	405,825	416,283	
8	% Change Yr over Yr		6.2%	-3.5%	4.8%	-5.7%	2.6%	0.85%
9	Operating Income per Retail Customer	2,191	2,198	2,209	2,451	2,437	2,492	
10	% Change Yr over Yr		0.3%	0.5%	11.0%	-0.6%	2.3%	2.69%

REFERENCE:
LINE 1: COMPANY RESPONSE TO RUCO DR 8.4; COMPANY SCHEDULE A-2
LINE 3: COMPANY RESPONSE TO RUCO DR 9.1; COMPANY SCHEDULE E-1
LINE 5: (LINE 3 / PAGE 3, LINE 3) * 1000
LINE 7: COMPANY RESPONSE TO RUCO DR 8.4; COMPANY SCHEDULE A-2
LINE 9: (LINE 1 / PAGE 3, LINE 3) * 1000

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-08-0172

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 19, 2008

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utility regulation and your educational background.

A. I have been involved with utility regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have also been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix 1, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Arizona Public Service Company's ("APS" or "the Company") amended application for a permanent rate increase ("Application") for the Company's electric service operations in the state of Arizona. APS filed the Application with the ACC on June 2, 2008. The Company has chosen the calendar year ended December 31, 2007 for the test year in this proceeding.

Q. Briefly describe APS.

A. APS is based in Phoenix, Arizona and is the largest investor-owned electric utility in the state. According to the most recent Value Line Investment Survey ("Value Line") report on the Company, APS provides electric generation, transmission and distribution services to approximately 1,780,000 customers in eleven of fifteen counties in Arizona. The Company's large service territory includes portions of the Phoenix metropolitan area in central Arizona; Flagstaff to the north; Parker and Yuma to the west; Holbrook to the east; and Ajo to the south. APS is a wholly owned subsidiary of Pinnacle West Capital Corporation ("Pinnacle West" or "Parent"), an Arizona corporation, also based in Phoenix, that is publicly traded on the New York Stock Exchange ("NYSE")[1]. The Company owns a portion of the Palo Verde Nuclear Generating Station,

[1] NYSE ticker symbol PNW

located in Wintersburg approximately 50 miles west of downtown Phoenix, and operates the plant for itself and the other owners that provide electric service to customers in Southern California, New Mexico and West Texas. Also according to Value Line, APS' generation mix, as of November, 2008, was comprised of 37 percent coal, 22 percent nuclear, 18 percent natural gas and other sources, and 23 percent purchased power.

Q. Please explain your role in RUCO's analysis of APS' Application.

A. I reviewed APS' Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of debt (the Company has no preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving APS?

A. No. I was involved with APS' last two rate case filings.

...

Q. Were you also responsible for conducting an analysis on the Company proposed revenue level, rate base and rate design?

A. No. Those portions of the case were handled by Ben Johnson Associates, a professional consulting firm located in Tallahassee, Florida.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this third section I will also provide a brief overview of the current economic climate that APS is operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on APS' cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of APS, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.60 percent cost of equity capital. This 9.60 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies.

Cost of Debt – I am recommending that the Commission adopt a 5.48 percent cost of long-term debt. This is based on my review of the costs associated with the various debt instruments issued by APS to finance the Company's assets devoted to the provision of service.

Capital Structure – I am recommending that the Company-proposed adjusted capital structure, which is comprised of 46.21 percent long-term debt and 53.79 percent common equity, be adopted by the Commission.

Cost of Capital – Based on the results of my recommended capital structure, cost of debt, and cost of equity analyses, I am recommending a 7.70 percent cost of capital for APS. This figure represents the weighted cost of my recommended cost of long-term debt and my recommended cost of common equity.

Q. Why do you believe that your recommended 7.70 percent cost of capital is an appropriate rate of return for APS to earn on its invested capital?

A. The 7.70 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as APS, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for APS?

A. Based on the results of my DCF and CAPM analyses, which ranged from 6.24 percent to 12.26 percent for a sample of electric providers, I am recommending a 9.60 percent cost of equity capital for APS. My recommended 9.60 percent figure represents a mean average of the results of my DCF and CAPM analyses, which utilized a sample of publicly traded electric companies.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate APS' cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

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

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine APS' cost of equity capital. It is similar to the model used by the Company.

Q. In determining the rate of future dividend growth for APS, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[2]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

[2] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony of Stephen G. Hill, dated December 10, 1993, pages 25 - 32.

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

...

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[3] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[4] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be

[3] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[4] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change only in the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

...

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[5] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,

b = the earnings retention ratio,

r = the return on common equity,

s = the fraction of new common stock sold that accrues to a current shareholder, and

[5] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

v = funds raised from the sale of stock as a fraction of existing equity.

and $v = 1 - \left(\frac{BV}{MP}\right)$

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M / B) + 1] / 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M / B) + 1] / 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

The same holds true for a utility (such as APS' Parent or three of the other electric utilities included in my sample) which has a market-to-book ratio of less than 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a Southwest Gas Corporation rate case[6] decided in February of 2006, the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group consisting of seventeen electric utility companies that have similar operating characteristics to APS.

...

[6] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

Q. Why did you use a proxy group methodology as opposed to a direct analysis of APS?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with APS itself. Although shares of APS' parent company, Pinnacle West, are traded on the NYSE, there is no financial data available on dividends paid on *publicly held* shares of APS. Consequently it was necessary to create a proxy by analyzing publicly traded electric companies with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the <u>Hope</u> decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your proxy for APS?

A. With the exception of three electric companies, I chose the same sample of electric providers that were used by APS' cost of capital witness, William E. Avera, Ph.D. All of the electric utility companies in my sample with the exception of three were used by Dr. Avera in his electric utility proxy group. Each of the electric utilities included in our samples are publicly traded on the NYSE, with the exception of Otter Tail Corporation, and are followed by Value Line's electric utility (east, central and west) industry segments. Otter Tail Corporation is traded on the NASDAQ[7] which is also a major U.S. stock exchange. Each of the companies in the proxy are engaged in the provision of regulated electric utility services. Attachment A of my testimony contains Value Line's most recent evaluation of the regional electric utility proxy group that I used for my cost of common equity analysis.

Q. What companies are included your proxy?

A. Schedule WAR-2 lists the seventeen electric service providers included in my proxy and their NYSE/NASDAQ ticker symbols.

Q. Did the Company's witness also perform a similar analysis using electric utility companies?

A. Yes. As I noted earlier, the Company's witness, Dr. Avera, performed a similar analysis that used all but three of the publicly traded electric utility companies included in my sample.

[7] National Association of Securities Dealers Automated Quotation system

Q. What three electric companies did you exclude from your sample?

A. My sample excludes Constellation Energy Group, Inc., Entergy Corporation, and Great Plains Energy Incorporated.

Q. Why did you exclude these three electric service providers from your sample?

A. In September of 2008, the management of Constellation Energy Group, Inc. accepted a buyout offer from MidAmerican Energy (a subsidiary of Warren Buffet's Berkshire Hathaway, Inc.). Consequently Value Line has suspended its projections on future performance because MidAmerican Energy's offer is now driving the price of Constellation Energy Group, Inc.'s stock. Value Line has also suspended its projections on Entergy Corporation as a result of recent heavy hurricane damage to that utility's assets in the State of Louisiana. My decision to eliminate Great Plains Energy Incorporated from my sample was based on non-meaningful Value Line projected sustainable growth information for the 2008 and 2009 operating periods. Because of the circumstances that I've just described, I did not consider the aforementioned electric utilities to be suitable for my cost of equity sample.

...

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2003 to 2007. Schedule WAR-5 also includes Value Line's projected 2008, 2009 and 2011-13 values for the retention ratio, return on book equity, book value per share growth rate, and number of shares outstanding for the electric utility companies in my sample.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use Ameren Corp., (NYSE symbol AEE) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 10 and 11 of my testimony) to multiply AEE's earned return on common equity by its earnings retention ratio for each year in the 2003 to 2007 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, AEE's sustainable internal growth rate ranged from 2.22 percent in 2003 to 2.16 percent in 2007. The company's growth rates experienced an up and down pattern during the observation period, resulting in a 1.49 percent average over the 2003 to 2007 time frame. Value Line's analysts are forecasting a drop in AEE's rate of sustainable growth to 1.72 percent during 2008 before AEE's sustainable growth rate increases to 2.08 percent in 2009 and 2.70 percent during the 2011-13. Based on my analysis of the aforementioned projections and estimates, I believe that a 2.25 percent rate of internal sustainable growth is reasonable for AEE.

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that AEE's share growth averaged 6.39 percent over the 2003 - 2007 observation period. However, Value Line expects future outstanding shares to increase from 208.73 million in 2007 to 222.00 million by the end of 2013. Taking this data into consideration, I am estimating a 1.00 percent rate of share growth for AEE over the period of 2008 through 2013 (Schedule WAR-4, Page 2, Column A, Line 2).

My final dividend growth rate estimate for AEE is 4.24 percent (2.25 percent internal growth + 1.99 percent external growth) and is shown on Schedule WAR-4, Page 1.

Q. What is your average dividend growth rate estimate using the DCF model for the sample electric utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 7.13 percent, which is also displayed on Schedule WAR-4, Page 1.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. As can be seen in Schedule WAR-6, my 7.13 percent estimate is 158 basis points higher than the 5.55 percent average of Value Line's and Zacks Investment Research's ("Zacks") projected and historic averages of earnings per share, dividends per share and book value per share. My 7.13 percent estimate is also 59 basis points higher than Value Line's 6.54 percent 5-year historic compound history. Both the Value Line and Zacks earnings projections (Attachment B) indicate that investors are expecting increased performance from electric utility companies in the future. Based on the information presented in Schedule WAR-6, I would say that my 7.13 percent estimate, which is close to Zacks' 7.64 percent projected EPS estimate, is a fair representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's most recent (i.e. September 26, 2008, November 7, 2008 and November 28, 2008) Ratings and Reports for the Electric Utility (Central, West and East) industry updates. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period September 29, 2008 to November 21, 2008.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric utilities included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 12.26 percent.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[8], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and

[8] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

risk as measured by beta.[9] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\ ß\ (r_m - r_f)\ ]$$

where: k = the expected return of a given security,

r_f = risk-free rate of return,

[9] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

β = beta coefficient, a statistical measurement of a security's systematic risk,

r_m = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a real rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used the most recent yield on a 5-year U.S. Treasury instrument which was published in Value Line's November 28, 2008 Selection and Opinion publication. (Attachment C). This resulted in a risk-free (r_f) rate of return of 2.02 percent.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury instrument closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2007[11] as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the yields of intermediate-term government bonds for the same eighty-one year period. The risk premium (r_m - r_f) that results by using these inputs is 5.10 percent (10.40% - 5.30% = 5.10%). The risk premium that results by using the arithmetic mean calculation is 6.80 percent (12.30% - 5.50% = 6.80%).

Q. How did you select the beta coefficients that were used in your CAPM model?

A. The beta coefficients (ß), for the electric utilities used in my proxy, were calculated by Value Line and were published in the most recent updates

[11] The historical information used to develop the market risk premium was published in Morningstar's Stocks Bonds bills and Inflation 2008 Yearbook.

(i.e. September 26, 2008, November 7, 2008 and November 28, 2008) for the Central, West and East regional electric providers in my sample. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDC's included in my sample ranged from 0.60 to 1.00 with an average beta of 0.83.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for r_m results in an average expected return of 6.24 percent. My calculation using an arithmetic mean results in an average expected return of 7.64 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	12.26%
CAPM	6.24% – 7.64%

Based on these results, my best estimate of an appropriate range for a cost of common equity for APS is 6.24 percent to 12.26 percent. My final recommendation for APS is 9.60 percent.

Q How did you arrive at your recommended 9.60 percent cost of common equity?

A. My recommended 9.60 percent cost of common equity is the average of my DCF and CAPM results. The calculation can be seen on Page 3 of Schedule WAR-1.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. Dr. Avera is recommending an 11.50 percent cost of equity for APS, which is 190 basis points higher than the 9.60 percent cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[12] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

[12] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the

Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in forty-five years.

Even though some signs of economic strength, mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[13]"

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the

[13] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[14] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to

[14] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[15]

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[16]. Since it began increasing the federal funds rate in June 2004, the Fed had assured investors that it would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[17]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would

[15] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

[16] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

[17] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

Q. Was the Fed's attempt to engineer a soft landing successful during the period that followed the August 8, 2006 FOMC meeting?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[18]

Q. What has been the state of the economy over the past two years?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

[18] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[19] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crises rooted in a deterioration of the market for subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[20] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal, [21] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate –

[19] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[20] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[21] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

possibly before the next FOMC meeting scheduled on September 18, 2007.

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What recent actions have the Fed taken in regard to interest rates?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members believed would moderate during the economic slowdown).[22] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has been described as the worst financial crisis since the 1930's[23]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another 50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008. The Fed's discount rate will go to 0.50 percent, a level not seen since 1940s.[24]

[22] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

[23] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

[24] Hilsenrath, Jon, "Fed Cuts Rates Near Zero to Battle Slump" The Wall Street Journal, December 17, 2008

Based on data released during the early part of December 2008, the U.S. is now officially in a recession which began in December of 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 2.00 percent from 5.73 percent in 2000.

Q. What has been the trend in other leading interest rates over the last year?

A. As of November 19, 2008, the leading interest rates have all dropped from the levels that existed a year ago (Attachment C). The prime rate has fallen from 7.50 percent a year ago to 4.00 percent. The benchmark federal funds rate, just discussed, has decreased from 4.50 percent, in November 2007, to a level of 0.25 percent (as a result of the December 16th rate cut discussed above). The yields on all of the maturities of U.S. Treasury instruments exhibited in my Attachment C have also decreased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[25], in which long-term rates fell as short-term

[25] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 5-year Treasury yield, used in my CAPM analysis, has fallen from 3.55 percent, in November 2007, to 2.02 percent as of November 19, 2008. The 1-Year Treasury constant maturity rate also decreased from 3.43 percent over the past year to 0.97 percent. These current yields are considerably lower than corresponding yields that existed during the early nineties and at the beginning of the current decade (as can be seen on Schedule WAR-8).

Q. What is the current outlook for the economy?

A. Value Line's analysts have been decidedly pessimistic in their outlook on the economy as of late and had this to say in their Economic and Stock Market Commentary that appeared in the December 12, 2008 edition of Value Line's Selection and Opinion publication:

> **The economic picture continues to darken**, with data recently showing additional slippage in manufacturing activity (to a 26-year low), a sharp decline in construction spending, and another setback in nonmanufacturing. Add to this, expectations for a weak holiday shopping season and for new turmoil in the housing and automobile industries and it is not hard to make a case that the current quarter could see a drop in the U.S. gross domestic product of 3% to 5%.

Value Line's analysts went on to state:

> **We face several difficult quarters up ahead**. Our sense is that the first and second quarters of 2009 will see declines in business activity of 2% to 3%, as the broad contraction in the economy drones on for a possible

> six to nine months more. At this point, none of the consumer and industrial markets that we view as critical to a sustained revival in economic activity (such as the housing, retail, auto, and manufacturing sectors) appears to be even close to bottoming out.

Q. What is Value Line's outlook for credit availability and interest rates?

A. In the recent Selection and Opinion publication noted above, Value Line's analysts had this to say:

> **Challenges will await the Obama Administration and the Federal Reserve**. Those challenges are likely to center around the need for greater credit availability, more lending by the banks, the adoption of a program to revive the auto industry, the passage of an effective stimulus plan, and, possibly, further in interest rate cuts. How well these issues are addressed will go a long way toward determining the severity of the recession, which the National Bureau of Economic Research now claims has been under way since December of 2007.

Value Line's analysts continued to state:

> **It is likely to be late next year before we see a durable economic comeback start to take hold**. Once that recovery does unfold, it is likely to be led, ironically, by the housing market, which was the first area of the economy to falter and could be the first to revive thanks to falling home prices and lower mortgage rates.

Q. How has the current economic environment of lower interest rates affected various regulated utility industries as a whole?

A. Value Line analyst Nils C. Van Liew took note of the environment of low interest rates that existed in the early part of 2007. In Value Line's Electric Utility (East) Industry update dated March 2, 2007, Mr. Van Liew had this to say:

> **Low Interest Rates.** Several factors are, no doubt, driving the electric utilities' strong share-price performance. Perhaps most important is a benign interest-rate environment. Utilities frequently tap the credit markets to fund their operations. (Low interest rates mean they can cost effectively build new power plants and maintain existing ones.) "Cheap money" also tends to drive economic expansion, thereby increasing electricity demand. That said, interest rates should remain relatively low,

> though the likelihood that the Federal Reserve eases (monetary) policy is small, given persistent inflation concerns.

Given the fact that interest rates are even lower now than they were at the time of Mr. Van Liew's writing, I believe that his views are still valid. Even though APS is in a position where new debt is not a desirable option, a low interest rate environment is one that makes equities more appealing to investors.

Q. Has the subprime mortgage crises had an impact on borrowing?

A. Yes. The situation has had a strong impact on liquidity for both banks and the capital markets. Hopefully the actions of both the U.S. Treasury and the Fed will succeed in eliminating the credit crunch that presently exists and restore the credit markets to their pre-subprime status.

Q. How are Value Line's analysts viewing the credit crunch as it relates to the electric utility industry?

A. In his Electric Utility (West) Industry update, Value Line analyst Paul E. Debbas, CFA, had this to say:

> The concerns about the credit crunch are most evident in the price of Constellation Energy's stock. Constellation is heavily involved in energy marketing, so liquidity and credit quality are extremely important. Wall Street's worries about the health of Constellation's non-regulated activities caused the stock — which was above $100 a share in January of 2008 — to plummet to $13 a share before rebounding after the company agreed to be taken over by a subsidiary of Berkshire Hathaway.
>
> So far, companies appear to have adequate liquidity. Also, there haven't been many downgrades by the credit rating agencies. But even some investment-grade issuers had to pay high interest rates on long-term

> debt that was issued in October, however. This is worrisome because allowed returns on equity have been declining, and there is no assurance that a reversal of this trend is in the offing.

Q. What are the current dividend yields of electric utility stocks followed by Value Line?

A. Dividend yields of electric utilities were also Value Line's Mr. Debbas in his November 7, 2008 industry update:

> So far this year, the Value Line Utility Average is down more than 30%. That's a lot, but it's not nearly as much as the nearly 50% decline in the Value Line Composite Average. As a result of the big drop off, the average yield of utility stocks is now 5%. From 2004 through 2007, it was below 4%.
>
> In general, stocks of companies that have a heavy non-regulated presence have fallen more than those of companies that are mostly or entirely regulated. In some cases, relative underperformance of a utility stock is due to a worsening of the company's prospects. In others, it is merely an overreaction.

Q. How does the 5.00 percent average yield on the fifty-eight electric utility stocks followed by Value Line compare with the average dividend yield of your sample electric utility companies?

A. As can be seen in Schedule WAR-3, my sample electric utility companies have an average dividend yield of 5.13 percent which is 13 basis points higher than the 5.00 percent average yield on electric utility stocks reported by Value Line's Mr. Debbas.

...

Q. After weighing the economic information that you've just discussed, do you believe that the 9.60 percent cost of equity capital that you have estimated is reasonable for APS?

A. I believe that my recommended 9.60 percent cost of equity will provide APS with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are low by historical standards) are taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return.

COST OF DEBT

Q. What is your recommended cost of long-term debt?

A. I am recommending a cost of long-tem debt of 5.48 percent.

Q. How does this compare to the cost of debt being proposed by APS?

A. My 5.48 percent recommended cost of long-term debt is 29 basis points lower than the 5.77 percent cost of long-term debt being proposed by APS.

...

Q. How did you calculate your recommended cost of long-term debt?

A. I relied on information on the costs of APS' various debt instruments that were exhibited in Pinnacle West's Form 10-K that was filed with the U.S. Securities and Exchange Commission on February 27, 2008. The 10-K was provided in the Company's Application to support the information presented in the standard filing D schedules on cost of capital. As can be seen on Page 2 of Schedule WAR-1, I calculated a weighted cost of debt of 5.48 percent. The cost rates for each of the itemized debt instruments were obtained from the aforementioned Pinnacle West Form 10-K (Attachment D).

CAPITAL STRUCTURE

Q. What capital structure is the Company proposing in this proceeding?

A. The Company is proposing an adjusted capital structure comprised of 46.21 percent long-term debt and 53.79 percent common equity.

Q. What capital structure are you proposing for APS?

A. I am recommending the same adjusted capital structure being proposed by APS.

Q. Is the capital structure proposed by APS in line with industry averages?

A. Yes. As can be seen in Schedule WAR-9, the capital structure proposed by APS is almost identical to the average capital structure of the electric utility companies included in my sample. The companies in my sample have capital structures comprised of approximately 46.2 percent debt and 53.8 percent equity (53.3 percent common equity and 0.50 percent preferred equity).

Q. In terms of risk, how does your recommended capital structure compare to the electric utility companies in your sample?

A. The electric utility companies in my sample would be considered as having the same level of financial risk (i.e. the risk associated with debt repayment) as APS.

WEIGHTED AVERAGE COST OF CAPITAL

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. The Company has proposed a weighted average cost of capital of 8.86 percent which is 116 basis points higher than my recommended 7.70 percent weighted average cost of capital

COMMENTS ON APS' COST OF EQUITY CAPITAL TESTIMONY

Q. Have you reviewed APS' testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony prepared by Dr. William E. Avera.

Q. What issues does Dr. Avera address in his cost of equity testimony?

A. In addition to addressing the cost of common equity issues in this case, Dr. Avera also addresses the capital structure, credit worthiness, and attrition adjustment issues that APS' has raised in its Application. Dr. Avera also argues that the Company-proposed unadjusted cost of common equity should be applied to a fair value rate base.

Q. Are there any disagreements between you and Dr. Avera in regard to the capital structure issue in this case?

A. No. As I stated earlier, I am recommending that the Commission adopt the Company-proposed capital structure comprised of 46.21 percent long-term debt and 53.79 percent common equity.

Q. Will you address those portions of Dr. Avera's testimony related to credit worthiness and an attrition adjustment?

A. No. RUCO witness Dr. Ben Johnson will address both of those issues in his direct testimony.

Q. Do you agree with Dr. Avera's argument that the unadjusted Company-proposed cost of equity should be applied to a fair value rate base?

A. No, I do not.

...

Q. Please explain.

A. This issue was recently decided on by the Commission in a remand proceeding involving Chaparral City Water Company, Inc. ("Chaparral")[26]. In that case, the Commission adopted a cost of common equity that was reduced by an inflation adjustment which took into consideration the effects of inflation that were reflected in Chaparral's fair value rate base. In arriving at its rate of return to be applied to Chaparral's fair value rate base, the Commission adopted a 200 basis point adjustment recommended by Dr. Ben Johnson, who was also RUCO's witness in the Chaparral remand case. In light of the Commission's Chaparral remand decision, I would recommend that a similar inflation adjustment be made to any Commission-adopted cost of common equity in the event that the Commission chooses not to adhere to its long standing method of determining a fair value rate of return.

Q. Please compare the Company-proposed cost of equity with your recommended cost of equity.

A. The Company is recommending a cost of equity capital of 11.50 percent which is 190 basis points higher than my recommended 9.60 percent cost of equity.

[26] Decision No. 70441, dated July 28, 2008.

Q. Have you studied the specific methods that Company witness Dr. Avera used to derive the Company-proposed cost of equity capital?

A. Yes.

Q. What methods did Dr. Avera use to arrive at his cost of common equity for APS?

A. Dr. Avera used the DCF and CAPM methods to estimate APS' cost of common equity.

Q. Can you provide a comparison of the results derived from Dr. Avera's models and yours?

A. Yes. The following portion of my testimony will compare and contrast the results of our DCF and CAPM analyses.

DCF Comparison

Q. Please compare the results of Dr. Avera's DCF analysis and the results of your DCF analysis.

A. Dr. Avera presented the results of two DCF analyses, one that relied on a sample of regulated electric utilities and the other on unregulated industrials. His DCF analysis using a sample of regulated utilities produced a final estimate of 11.00 percent and his DCF analysis using a sample of unregulated industrials produced a final estimate of 12.70 percent. My DCF analysis, which relied on a sample of all but three of the regulated electric utilities included in Dr. Avera's sample, produced a final estimate of 12.26 percent which falls between Dr. Avera's regulated and unregulated results.

Q. Why didn't you perform an analysis that included unregulated industrials?

A. Quite simply because I believe that a sample of regulated electric utilities that face the same types of risks and operating conditions that APS does is an appropriate sample.

Q. What was the difference between Dr. Avera's dividend yield results for electric utilities and your dividend yield results?

A. Dr. Avera's DCF analysis of regulated electric utilities produced an average dividend yield of 3.72 percent as opposed to my average dividend yield of 5.13 percent. I attribute the majority of the 142 basis point difference to lower closing stock prices that I recorded during my 8-week observation period.

Q. Please compare your respective DCF growth estimates (g) for electric utilities.

A. Dr. Avera's electric utilities DCF analysis produced an average growth estimate of 9.90 percent which is 277 basis points higher than my 7.13 percent estimate.

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Dr. Avera conducted his?

A. Yes. Dr. Avera relied on projections from two other agencies other than Value Line (Reuters and I/B/E/S) as opposed to my reliance on Value Line and Zacks. The fact that Dr. Avera relied on one additional data source does not appear to be problematic since Reuters and I/B/E/S' projections are very similar (11.40 percent and 11.60 percent respectively. However, I will point out that Dr. Avera's DCF analysis placed no emphasis on the past performance of the electric utilities in his sample and focused entirely on analysts' future projections to estimate the growth component (g) of the DCF model. While I agree that the estimation of an appropriate cost of common equity is a forward looking process, I believe that past performance should not be ignored entirely. Consideration of utilities' past performance should serve as a useful check on the reasonableness of analysts' future expectations. In addition to my points above, Dr. Avera eliminates high and low results (i.e. outliers) from his DCF results in order to arrive at his final DCF cost of common equity estimate.

Q. Have you removed such outliers from your analysis?

A. No. While I will admit that several of my sample electric utilities had results that could be classified as being extremely high or low, I have decided not to ignore them. In short, I am willing to recognize the fact that we are not operating in a "normal" economic environment at this time given the current state of the financial markets. Consequently, I am willing to give the benefit of a doubt to the more extreme results that my DCF model produced.

CAPM Comparison

Q. Please compare the results of Dr. Avera's CAPM analysis and the results of your CAPM analysis.

A. Dr. Avera's CAPM analysis produced an estimate of 12.20 percent for his sample of electric utilities and an estimate of 11.1 percent for his sample of unregulated industrials. His estimates are 596 basis points to 486 basis points higher than my 6.24 percent CAPM estimate that uses a geometric mean and are 456 basis points to 346 basis points higher than my 7.64 percent CAPM estimate that uses a geometric mean.

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Dr. Avera conducted his?

A. There are two main differences between Dr. Avera's CAPM analysis and mine. The first difference involves Dr. Avera's use of a one month average (December 2007) of the higher yields of 20-year Treasury bonds as opposed to the more recent spot yield of a 5-year Treasury instrument that I relied on for the risk-free rate of return. The second difference involves his market risk premium.

Q. Please compare the differences in the risk free rates that you and Dr. Avera relied on.

A. Dr. Avera's risk free rate is 4.60 percent as opposed to my risk free rate of 2.02 percent. As I noted earlier in my testimony, I believe a 5-year treasury instrument is more appropriate since Arizona utilities generally apply for rates every three to five years on average. Dr. Avera's chosen 20-year Treasury bond instrument also has a current yield of approximately 3.60 percent (Attachment C).

Q. Did Dr. Avera use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However, Dr. Avera used an average Value Line beta of 0.89 as opposed to my average Value Line beta of 0.83 (using a sample that excluded three of the electric utilities used by Dr. Avera). Dr. Avera's beta for unregulated industrials was 0.76.

Q. What was the difference between Dr. Avera's market risk premiums and your market risk premiums?

A. Dr. Avera used a market risk premium of 8.60 percent for both his regulated electric utility sample and his unregulated industrials sample. I used market risk premiums of 5.10 percent and 6.80 percent in my respective CAPM models using geometric and arithmetic means.

Q. Can you explain the reason why Dr. Avera's risk premium is higher than yours?

A. Dr. Avera utilized his own method for calculating the return on the market as opposed to relying on the more established method of relying on historical market data published in Morningstar. His calculated market return figure of 13.20 percent is 280 basis points higher than my 10.40 percent return on the market using a geometric mean and 90 basis points higher than my 12.30 percent return on the market using an arithmetic mean. Dr. Avera arrives at his 8.60 percent market risk premium by subtracting his 4.60 percent risk free rate of return from his aforementioned return on the market of 13.20 percent.

Q. How do these results compare to APS' parent, Pinacle West, on a stand alone basis?

A. Pinnacle West has a Value Line beta of 0.80 which is lower than Dr. Avera's average beta of 0.89 and my average beta of 0.83. Using Pinnacle West's 0.80 beta in Dr. Avera's CAPM model produces an expected return of 11.48 percent as opposed to expected returns of 6.10 percent and 7.46 percent in my CAPM models.

Final Cost of Equity Estimate

Q. How did Dr. Avera arrive at his final 11.50 percent cost of equity capital for APS?

A. Dr. Avera's final cost of equity estimate of 11.50 percent falls within the 11.00 percent to 12.7 percent range of results obtained from his DCF and CAPM models.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Dr. Avera or any other witness for APS constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on APS?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF CHAPARRAL CITY WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02113A-07-0551

REPLY TO CHAPARRAL CITY WATER COMPANY RESPONSE

Pacific Life Insurance Company ("Pacific Life") hereby replies to "Chaparral City Water Company's Response to Pacific Life Insurance Company's Motion for Leave to Present Testimony" ("Response"). Pacific Life will ignore Chaparral City's disparagement of its counsel.

I. Chaparral City Seeks to Renege on Its Agreement Not to Oppose the Testimony

No other party opposed hearing Mr. Green's testimony. On December 11, 2008, Chaparral City stated by e-mail to the parties and Judge Wolfe that it would also not oppose hearing Mr. Green's testimony.

> While we are frustrated that Pacific Life would place the ACC and the parties in the position that they have, Chaparral City will not oppose the late filed testimony or witness appearance at the Phase Two hearings on the conditions that their witness is called as the last witness on 1/9 and that the issue is part of the Phase 1 briefs as Mr. Marks already offered.[1]

Chaparral City accepted these conditions by an e-mail dated December 13, 2008, agreeing that Mr. Green's testimony would be heard following completion of all other testimony scheduled for January 9, 2009. Chaparral City now seeks to go back on on its agreement with Pacific Life.

[1] December 11, 2008, E-mail from Mr. Shapiro to Judge Wolfe, emphasis added. Copy attached as Exhibit A,

II. Mr. Green's Testimony Will Not Delay This Case.

Allowing Mr. Green to testify will not delay this case. Pacific Life is not asking to reopen the record, but to take advantage of an additional hearing day that has already been scheduled. Chaparral City does pause its foot-stomping long enough to admit that Pacific Life's issues are "relatively straightforward." Further, because the testimony does not concern its revenue requirement, Chaparral City should not have any real issue with it. Mr. Green's concise single-issue testimony should proceed quickly, even if it is followed by short responsive testimony from other parties. Finally, because the subject of Mr. Green's testimony will be addressed in Phase I briefs, it will not delay the ultimate resolution of this case.

III. There Is No Record Evidence on The Important Subject of This Testimony

Chaparral City claims that the subject of this testimony could be part of public comment. However, as Chaparral City well knows, a party cannot present public comment and public comment is not evidence. Mr. Green discusses the impact of the proposed irrigation rate increase on the golf course he manages. The record will benefit by including his testimony concerning this important issue.

IV. Requested Relief

Pacific Life again asks that the Administrative Law Judge allow the attached testimony to be heard. Pacific Life does not object to Mr. Green testifying after all witnesses presently scheduled for January 9, 2009. To avoid delaying the resolution of this case, Pacific Life also agrees that its issue should be part of the Phase I briefs due on January 23, 2009.

Respectfully submitted on December 17, 2008, by:

/s/Craig A. Marks
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Original and 13 copies **filed**
on December 17, 2008, with:

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Copy of the foregoing **mailed and e-mailed**
On December 17, 2008, to:

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1110 West Washington, Suite 220
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By: /s/Craig A. Marks
Craig A. Marks

Exhibit A

Craig Marks

From: SHAPIRO, JAY [JSHAPIRO@FCLAW.COM]
Sent: Thursday, December 11, 2008 6:48 PM
To: Teena Wolfe
Cc: Craig Marks; mwood@azruco.gov; Ernest Johnson; rmitchell@azcc.gov; JAMES, NORM
Subject: RE: Motion For Leave to Present Testimony

Judge Wolfe--in an effort to avoid more filings and/or procedural conferences, we thought we would use "Reply All" to let you and the other parties know our position on this motion by Pacific Life.

While we are frustrated that Pacific Life would place the ACC and the parties in the position that they have, Chaparral City *will not oppose* the late filed testimony or witness appearance at the Phase Two hearings on the conditions that their witness is called as the last witness on 1/9 and that the issue is part of the Phase 1 briefs as Mr. Marks already offered.

Please let us know if we need to address this matter further.

Jay

From: Craig Marks [mailto:craig.marks@azbar.org]
Sent: Thursday, December 11, 2008 12:39 PM
To: Teena Wolfe; Ernest Johnson; rmitchell@azcc.gov; JAMES, NORM; SHAPIRO, JAY; mwood@azruco.gov
Subject: Motion For Leave to Present Testimony

I've attached a courtesy copy of Pacific Life's Motion for Leave to Present Testimony. This is being filed today.

Craig

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Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power	E-01933A-07-0402	Rate Increase
Southwest Gas Corporation	G-01551A-07-0504	Rate Increase
Chaparral City Water Company	W-02113A-07-0551	Rate Increase

ATTACHMENT A

All of the major utilities in the eastern region of the United States are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western providers are covered in Issue 11.

Electric utility stocks have traded sharply lower with the broader markets in the three months since our last overview. Within the Eastern utility group, losers outnumbered gainers ten to one, with nearly half of the former selling off 25% or more. New York-based *CH Energy* led the group. It shares eked out a 3% gain. Shares of *Constellation Energy*, meanwhile, posted a group-worst 61% decline.

Weak Interim Results

The group posted generally weak September-quarter results. Indeed, fully two-thirds of the electric utilities reported lower year-over-year interim profits. A sputtering U.S. economy is largely to blame. In many regions, industrial-power demand has been declining as companies reduce production. Residential customers are also likely using power more prudently, given tighter household budgets. The fourth-quarter outlook is in a word "mixed". The current split between higher- and lower-expected year-over-year earnings is about 50-50.

Spending Cuts

Utilities are cutting back on spending and/or delaying nonessential infrastructure projects these days. New Jersey-based *Public Service Enterprise*, for example, plans to cut its 2009 capital budget by up to $325 million and suspend the $658 million remaining on its stock-buyback authorization. Utilities, from *Duke Energy* to *Exelon Corp.*, have announced similar moves. The pullbacks are largely the result of tighter capital markets and an associated increase in borrowing rates. They may very well lead to more modest rate-base expansion and consequently slower earnings growth.

Dividends

Utilities are praised for the generally reliable income streams that they provide investors in the form of regular quarter dividends. With that in mind, the median dividend yield for the group is currently 4.9%, some

INDUSTRY TIMELINESS: 57 (of 99)

140 basis points above the *Value Line* universe as a whole. Due to sharp sell offs in their shares, *TECO Energy* and *Constellation Energy* currently sport the fattest yields. We like the former for its total-return potential (dividends, plus share-price gains) over the pull to 2011-2013. By virture of its coal-mining operations, Tampa-based *TECO* is somewhat of a stealth commodity play (for better or worse).

Odds And Ends

We recently bid adieu to Energy East Corp., Spain's IBERDROLA having completed its $4.5 billion ($28.50 a share) acquisition of the Maine-based electric utility on September 17th. *Constellation* may be the next to go. MidAmerican Energy, a subsidiary of Berkshire Hathaway, has offered to buy the beleaguered utility-holding company for $4.7 billion, or $26.50 a share. *Constellation* shares are currently trading 10% below the proposed takeout price, providing trading accounts a decent arbitrage opportunity. Still, unfortunate investors that bought CEG shares at their peak ($108 a share) eleven months ago have little more to show for it other than a low effective yield on their original investment (1.8%) and a potential tax-loss-selling benefit.

Conclusion

At the present time, we recommend that investors take a fairly cautious stance towards the Eastern utility group. The broad economic slowdown and the prospect of more-modest rate base expansion suggest that earnings growth could take a hit. At the same time, the broad market sell off has led to increasingly competitive yields elsewhere and generally higher nonutility share-price recovery potential. On a positive note, the long-term trend, with respect to power demand, should remain positive, as electricity increasingly drives and recharges everything from iPods to new low- and no-emission vehicles. As always, we recommend that investors read each report carefully before making any investment decisions.

Nils C. Van Liew

Composite Statistics: Electric Utility Industry

2004	2005	2006	2007	2008	2009		11-13
287.3	323.9	345.4	363.7	***375***	***390***	Revenues ($bill)	***440***
20.4	22.4	26.2	28.8	***29.5***	***32.0***	Net Profit ($bill)	***37.0***
30.4%	29.6%	31.8%	33.4%	***34.5%***	***34.5%***	Income Tax Rate	***34.5%***
3.5%	3.9%	4.6%	6.0%	***7.0%***	***7.0%***	AFUDC % to Net Profit	***4.0%***
56.0%	54.6%	51.6%	50.8%	***51.0%***	***51.0%***	Long-Term Debt Ratio	***49.0%***
42.9%	44.2%	47.4%	48.1%	***48.0%***	***48.0%***	Common Equity Ratio	***50.0%***
424.0	429.9	491.0	496.7	***490***	***515***	Total Capital ($bill)	***565***
433.0	449.0	515.7	535.1	***520***	***540***	Net Plant ($bill)	***570***
6.7%	7.0%	7.0%	7.4%	***7.0%***	***7.5%***	Return on Total Cap'l	***8.0%***
10.9%	11.5%	11.0%	11.8%	***11.0%***	***11.5%***	Return on Shr. Equity	***13.0%***
11.1%	11.6%	11.1%	11.9%	***11.5%***	***11.5%***	Return on Com Equity	***13.0%***
4.9%	5.0%	5.4%	5.5%	***5.5%***	***5.5%***	Retained to Com Eq	***5.0%***
56%	57%	52%	55%	***55%***	***55%***	All Div'ds to Net Prof	***60%***
14.6	16.1	15.0	17.0			Avg Ann'l P/E Ratio	***14.5***
.77	.86	.81	.90	*Bold figures are Value Line estimates*		Relative P/E Ratio	***.95***
3.8%	3.5%	3.4%	3.2%			Avg Ann'l Div'd Yield	***3.9%***

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2005	2006	2007
% Change Retail Sales (kwh)	+5.4	+1.3	+2.2
Average Indust. Use (mwh)	1568	1578	1571
Avg. Indust. Revs. per kwh (¢)	5.73	6.10	6.35
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.2	+1.7	+.7
Fixed Charge Coverage (%)	253	265	289

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

All of the major electric utilities in the central United States are reviewed in this Issue. Those that serve the western region may be found in Issue 11. The eastern companies are covered in Issue 1.

Utilities—and their customers—are feeling the effects of inflation. The cost of materials, labor, fuel, and nonfuel operating and maintenance expenses is rising. This leads to higher bills for ratepayers.

Constellation Energy agreed to be acquired after its stock fell sharply amidst worries about the company's energy trading and marketing operations. It remains to be seen whether any other companies will be affected.

Electric utility stocks, as a group, are still pricey.

Everything Is Becoming More Expensive

Electric utilities are experiencing inflation in capital and operating costs. Building materials such as steel, copper, and concrete are considerably more expensive than they were in the early 2000s. Labor costs are also up. The cost of fossil fuels such as coal and natural gas is much higher than it used to be, too. (The rise in oil prices isn't as big a problem for electric generation in this industry because very little oil is used for this purpose, except in Hawaii.) Even the cost of nuclear fuel has risen. Nonfuel operating and maintenance expenses are going up as well. Healthcare costs are a concern for this industry just as for most other sectors. Property taxes are up, too.

These rising costs are being felt by customers. (Even if there was no inflation, capital spending would be rising anyway due to environmental compliance, growth of the transmission and distribution system, and new generating capacity.) Electric utilities that are still traditionally regulated are filing rate cases and receiving rate increases. Among the companies in this Issue, utility subsidiaries of *American Electric Power, Ameren, DTE Energy, Cleco, Integrys Energy, ALLETE, NiSource, OGE Energy, MGE Energy, Westar Energy*, and *Alliant Energy* have electric rate applications pending. In states in which the generation portion of customers' bills has been deregulated, electric users are paying more, too, because the companies that own nonregulated generating assets are bidding higher prices in the auctions that are used to determine generating rates.

INDUSTRY TIMELINESS: 52 (of 99)

As long as regulatory treatment is reasonable—as it has been in most states of late—utilities can count on recovery of most of their costs, even as prices rise. However, companies can't count on reasonable regulatory orders to continue indefinitely. State regulatory commissions are aware that many customers are struggling to cope with higher electric bills. In order to place new utility plant in the rate base and recover higher expenses, utilities might well have to accept reductions in their allowed returns on equity.

The Constellation Energy Deal

The stock of Constellation Energy, which was more than $100 a share earlier this year, plummeted last week due to the market's worries about its energy trading and marketing activities. Wall Street was concerned about its exposure to troubled firms such as Lehman Brothers, and, most significantly, the possibility of downgrades by rating agencies. A significant downgrade in the company's credit rating would force Constellation to post significant amounts of collateral. As a result, the company's board of directors was willing to accept a takeover offer from MidAmerican Energy Holdings (a subsidiary of Berkshire Hathaway) for cash of $26.50 a share. For further details about the transaction, see our supplementary report in this Issue.

It's too early to tell whether Constellation's troubles will wind up affecting other companies that have a large presence in nonregulated energy marketing. Companies that have a large presence in this area include Exelon, Public Service Enterprise Group, PPL Corporation, FirstEnergy, and Sempra Energy. These stocks have weakened lately along with the overall market, but have not seen a deterioration comparable with what Constellation experienced.

Investment Advice

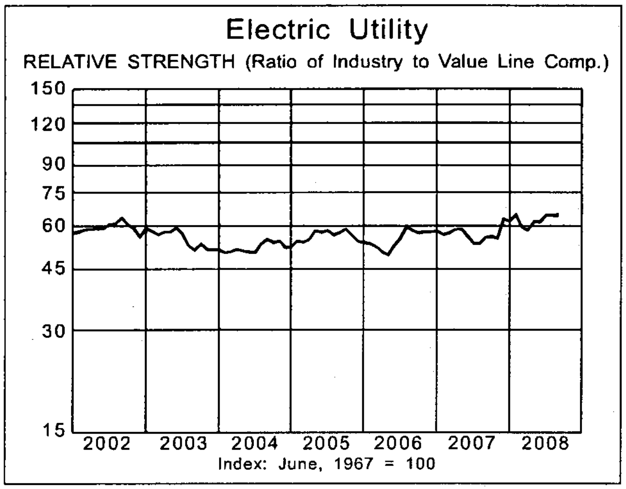
The Value Line Utility Average (which includes other utility stocks, not just electrics) has fallen as much as the Value Line Composite Average since the start of 2008, despite this industry's reputation as a defensive one. Even with their weak performance, many of these equities are trading within their 2011-2013 Target Price Range. This suggests that valuations are high.

We suggest that readers examine our industry review on the Electric Utility Industry that was published in the September 12th edition of *Selection & Opinion*.

Paul E. Debbas, CFA

Composite Statistics: Electric Utility Industry

2004	2005	2006	2007	2008	2009		11-13
287.3	323.9	345.4	363.7	**360**	**380**	Revenues ($bill)	**450**
20.4	22.4	26.2	28.8	**29.0**	**32.0**	Net Profit ($bill)	**40.0**
30.4%	29.6%	31.8%	33.4%	**34.5%**	**34.5%**	Income Tax Rate	**35.0%**
3.5%	3.8%	4.5%	5.8%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**7.0%**
56.0%	54.6%	51.6%	50.6%	**51.0%**	**50.5%**	Long-Term Debt Ratio	**49.5%**
42.9%	44.2%	47.4%	48.3%	**48.5%**	**49.0%**	Common Equity Ratio	**50.0%**
424.0	429.9	491.0	495.3	**495**	**525**	Total Capital ($bill)	**620**
433.0	449.0	515.7	535.1	**540**	**580**	Net Plant ($bill)	**665**
6.7%	7.0%	7.0%	7.4%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
10.9%	11.5%	11.0%	11.8%	**11.0%**	**11.0%**	Return on Shr. Equity	**11.5%**
11.1%	11.6%	11.1%	11.9%	**11.0%**	**11.5%**	Return on Com Equity	**11.5%**
4.9%	5.0%	5.4%	5.5%	**5.0%**	**5.0%**	Retained to Com Eq	**5.0%**
56%	57%	52%	55%	**62%**	**60%**	All Div'ds to Net Prof	**59%**
16.1	15.0	17.0	17.1			Avg Ann'l P/E Ratio	**14.0**
.86	.81	.90	.91	*Bold figures are Value Line estimates*		Relative P/E Ratio	**.95**
3.5%	3.4%	3.2%	3.1%			Avg Ann'l Div'd Yield	**3.9%**



ELECTRIC UTILITY (WEST) INDUSTRY

All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

With the economy showing signs of severe weakness, and possibly in a recession, we will examine how this will affect utilities.

We will also look at the effects of the credit crunch on this industry.

There has been a wider-than-usual variance in the performance of utility stocks since the steep broad-market downturn began. Not all utility equities are cheap.

What The Economy Means To Utilities

No matter what the state of the economy is, residential customers still have to light their homes and use appliances, entertainment equipment, and computers. This helps mitigate the effects of economic weakness on electric utilities. But these companies are hardly recession-proof. Demand for power from industrial customers, and commercial customers to a lesser extent, is influenced by the health of the economy. Some electric companies are already seeing year-to-year declines in sales to their largest customers. What's more, since economic hard times make it difficult for some residential customers to pay their bills, many utilities will have to increase their reserves for uncollectible accounts, if they have not already done so. Many customers have already stepped up their conservation efforts due to price elasticity. All of this means that there might well be a deceleration of utilities' earnings growth rates, or even a decline in profits.

Some utilities have already been experiencing a slowdown in customer growth, and demand, as a result of the slump in the housing market. This includes the utilities that serve most of Florida; *Pinnacle West*, which owns Arizona Public Service; and *Sierra Pacific Resources*, which owns Nevada Power and provides electricity to southern Nevada.

Any industrywide decline in the demand for power might well have negative implications for companies that own nonregulated power plants. Among these are Exelon, Constellation Energy, Public Service Enterprise Group, and PPL Corporation. Note, though, that market prices (and the profitability of these plants) is determined in part by the cost of natural gas, which sets prices in the wholesale markets because it is used to fuel intermediate and peaking plants.

INDUSTRY TIMELINESS: 61 (of 99)

One mildly positive effect of the worldwide economic weakness is the decline in commodity prices that has ensued. Electric utilities had to raise their capital budgets to reflect higher costs for steel, concrete, copper, and other building materials. Now, they will likely get a bit of relief. Lower-than-expected demand for power is also likely to have a moderating effect on capital spending.

The Credit Crunch

The concerns about the credit crunch are most evident in the price of Constellation Energy's stock. Constellation is heavily involved in energy marketing, so liquidity and credit quality are extremely important. Wall Street's worries about the health of Constellation's nonregulated activities caused the stock—which was above $100 a share in January of 2008—to plummet to $13 a share before rebounding after the company agreed to be taken over by a subsidiary of Berkshire Hathaway.

So far, companies appear to have adequate liquidity. Also, there haven't been many downgrades by the credit-rating agencies. But even some investment-grade issuers had to pay high interest rates on long-term debt that was issued in October, however. This is worrisome because allowed returns on equity have been declining, and there is no assurance that a reversal of this trend is in the offing.

Conclusion

So far this year, the Value Line Utility Average is down more than 30%. That's a lot, but it's not nearly as much as the nearly 50% decline in the Value Line Composite Average. As a result of the big dropoff, the average yield of utility stocks is now 5%. From 2004 through 2007, it was below 4%.

In general, stocks of companies that have a heavy nonregulated presence have fallen more than those of companies that are mostly or entirely regulated. In some cases, relative underperformance of a utility stock is due to a worsening of the company's prospects. In others, it is merely an overreaction. Among the stocks in this Issue, we advise investors to consider *MDU Resources*, which has fallen sharply due to the decline in gas and oil prices. *Black Hills Corporation* offers an attractive yield and dividend growth potential. By contrast, *Hawaiian Electric Industries*, whose stock is actually up for the year, has become wildly overvalued as a result.

Paul E. Debbas, CFA

Composite Statistics: ELECTRIC UTILITY INDUSTRY

2004	2005	2006	2007	2008	2009		11-13
289.0	325.3	346.8	365.2	**360**	**380**	Revenues ($bill)	**445**
20.2	22.2	26.1	28.8	**29.0**	**32.0**	Net Profit ($bill)	**40.0**
30.4%	29.6%	31.8%	33.4%	**34.5%**	**35.0%**	Income Tax Rate	**35.0%**
3.6%	3.8%	4.5%	5.8%	**7.0%**	**8.0%**	AFUDC % to Net Profit	**5.0%**
56.1%	54.6%	51.6%	50.6%	**51.0%**	**50.5%**	Long-Term Debt Ratio	**49.5%**
42.8%	44.2%	47.4%	48.3%	**48.5%**	**48.5%**	Common Equity Ratio	**50.0%**
427.5	433.1	493.7	497.7	**495**	**525**	Total Capital ($bill)	**620**
435.8	450.9	517.6	537.2	**540**	**580**	Net Plant ($bill)	**665**
6.6%	6.9%	6.9%	7.4%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
10.7%	11.3%	10.9%	11.7%	**11.0%**	**11.5%**	Return on Shr. Equity	**11.5%**
10.9%	11.5%	11.0%	11.8%	**11.5%**	**11.5%**	Return on Com Equity	**11.5%**
4.8%	4.9%	5.3%	5.4%	**5.0%**	**5.0%**	Retained to Com Eq	**5.0%**
57%	58%	52%	55%	**61%**	**60%**	All Div'ds to Net Prof	**59%**
14.8	16.3	15.1	17.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**14.5**
.78	.87	.82	.91			Relative P/E Ratio	**.95**
5.9%	3.5%	3.4%	3.2%			Avg Ann'l Div'd Yield	**3.9%**

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2005	2006	2007
% Change Retail Sales (kwh)	+5.4	+1.3	+2.2
Average Indust. Use (mwh)	1568	1578	1571
Avg. Indust. Revs. per kwh (¢)	5.73	6.10	6.35
Capacity at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.2	+1.7	+.3
Fixed Charge Coverage (%)	253	265	289

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

ALLETE NYSE-ALE

RECENT PRICE	44.45	P/E RATIO	16.3 (Trailing: 17.5, Median: NMF)	RELATIVE P/E RATIO	1.07	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS 3 Lowered 11/9/07

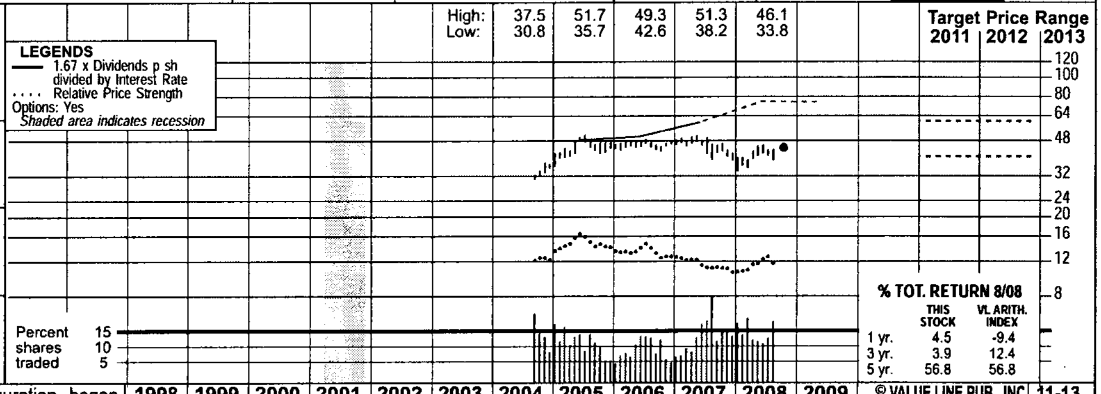
SAFETY 2 New 10/1/04

TECHNICAL 3 Lowered 9/26/08

BETA .85 (1.00 = Market)

	2004	2005	2006	2007	2008
High:	37.5	51.7	49.3	51.3	46.1
Low:	30.8	35.7	42.6	38.2	33.8

Target Price Range 2011 | 2012 | 2013



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+35%)	11%
Low	40	(-10%)	2%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	1	0	0	0	0
Options	0	1	0	0	0	0	0	1	0
to Sell	0	1	0	0	0	0	0	2	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	83	62	79
to Sell	75	86	63
Hld's(000)	18543	18034	18955

Percent shares traded 15 10 5

% TOT. RETURN 8/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	4.5	-9.4
3 yr.	3.9	12.4
5 yr.	56.8	56.8

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
--	--	--	--	--	--	25.30	24.50	25.23	27.33	25.70	26.35	Revenues per sh	27.75
--	--	--	--	--	--	2.97	3.85	4.14	4.42	4.05	4.30	"Cash Flow" per sh	5.25
--	--	--	--	--	--	1.35	2.48	2.77	3.08	2.70	2.90	Earnings per sh A	3.25
--	--	--	--	--	--	.30	1.25	1.45	1.64	1.72	1.80	Div'd Decl'd per sh B ■ †	2.00
--	--	--	--	--	--	2.12	1.95	3.37	6.82	9.80	11.30	Cap'l Spending per sh	7.00
--	--	--	--	--	--	21.23	20.03	21.90	24.11	25.45	27.15	Book Value per sh C	32.25
--	--	--	--	--	--	29.70	30.10	30.40	30.80	32.30	33.60	Common Shs Outst'g D	36.50
--	--	--	--	--	--	25.2	17.9	16.5	14.8	Bold figures are		Avg Ann'l P/E Ratio	15.5
--	--	--	--	--	--	1.33	.95	.89	.78	Value Line		Relative P/E Ratio	1.05
--	--	--	--	--	--	.9%	2.8%	3.2%	3.6%	estimates		Avg Ann'l Div'd Yield	4.0%
--	--	--	--	--	--	751.4	737.4	767.1	841.7	830	885	Revenues ($mill)	1015
--	--	--	--	--	--	38.5	68.0	77.3	87.6	80.0	90.0	Net Profit ($mill)	110
--	--	--	--	--	--	38.8%	28.4%	37.5%	34.8%	38.0%	38.0%	Income Tax Rate	38.0%
--	--	--	--	--	--	1.8%	.4%	.8%	2.3%	5.0%	7.0%	AFUDC % to Net Profit	3.0%
--	--	--	--	--	--	38.2%	39.1%	35.1%	35.6%	41.0%	42.5%	Long-Term Debt Ratio	46.0%
--	--	--	--	--	--	61.8%	60.9%	64.9%	64.4%	59.0%	57.5%	Common Equity Ratio	54.0%
--	--	--	--	--	--	1020.7	990.6	1025.6	1153.5	1395	1595	Total Capital ($mill)	2200
--	--	--	--	--	--	883.1	860.4	921.6	1104.5	1370	1695	Net Plant ($mill)	2325
--	--	--	--	--	--	5.1%	8.0%	8.6%	8.6%	6.5%	6.5%	Return on Total Cap'l	6.5%
--	--	--	--	--	--	6.1%	11.3%	11.6%	11.8%	9.5%	9.5%	Return on Shr. Equity	9.5%
--	--	--	--	--	--	6.1%	11.3%	11.6%	11.8%	9.5%	9.5%	Return on Com Equity E	9.5%
--	--	--	--	--	--	4.7%	5.2%	5.0%	5.8%	3.0%	3.0%	Retained to Com Eq	3.5%
--	--	--	--	--	--	23%	54%	57%	51%	69%	67%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 6/30/08

Total Debt $559.3 mill. **Due in 5 Yrs** $41.0 mill.
LT Debt $538.5 mill. **LT Interest** $29.7 mill.
(LT interest earned: 6.0x)
Leases, Uncapitalized Annual rentals $8.1 mill.

Pension Assets-12/07 $405.6 mill. **Oblig.** $420.4 mill.

Pfd Stock None

Common Stock 30,976,329 shs.

MARKET CAP: $1.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+2.0	+1.1	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	3.93	4.15	4.82
Capacity at Peak (Mw)	1512	1761	1701
Peak Load, Winter (Mw)	1543	1586	1614
Annual Load Factor (%)	80.0	80.0	80.0
% Change Customers (avg.)	+1.1	+1.3	+1.3
Fixed Charge Cov. (%)	461	503	503

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	--	--	1.5%
"Cash Flow"	--	--	4.0%
Earnings	--	--	2.5%
Dividends	--	--	5.5%
Book Value	--	--	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2005	193.3	174.4	177.4	192.3	737.4
2006	192.5	178.3	199.1	197.2	767.1
2007	205.3	223.3	200.8	212.3	841.7
2008	213.4	189.8	211.8	215	830
2009	220	215	225	225	885

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2005	.64	.38	.58	.88	2.48
2006	.68	.49	.78	.82	2.77
2007	.93	.80	.58	.77	3.08
2008	.82	.37	.70	.81	2.70
2009	.85	.45	.75	.85	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	--	--	--	.30	.30
2005	.30	.315	.315	.315	1.25
2006	.363	.363	.363	.363	1.45
2007	.41	.41	.41	.41	1.64
2008	.43	.43	.43		

BUSINESS: ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 141,000 customers in northeastern Minn., and Superior Water, Light & Power in northwestern Wisc. Electric revenue mix, '07: taconite mining/processing, 28%; paper/wood products, 11%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 13% other, 15%. Has real estate operation in Florida. Discontinued water-utility ops. in '01. Spun off automotive remarketing ops. (ADESA) in '04. Generating sources, '07: coal & lignite, 62%; hydro, 3%; purchased, 35%. '07 deprec. rate: 2.5%. Has 1,500 employees. Chairman, President & CEO: Donald J. Shippar. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's Minnesota Power subsidiary has a rate case pending. The utility requested a tariff hike of $45 million (9.5%) based on a return of 11.15% on a common-equity ratio of 54.8%. An interim rate increase of $36 million (7.5%) took effect at the start of August. The net effect on revenues over the last five months of 2008 will be $13 million, since the original request includes $8 million of riders that are already being paid by customers. The final order from the Minnesota commission is expected by mid-2009.

ALLETE's utility subsidiary in Wisconsin has filed a rate request, too. Superior Water, Light & Power is seeking a rate boost of $4 million (5%) based on a return of 11.5% on a common-equity ratio of 57.1%. New tariffs are expected to take effect in January of 2009.

A sharp decline in profitability from ALLETE's real estate business will almost certainly cause corporate profits to decline significantly in 2008. This operation is feeling the effects of the real estate slump in Florida. It suffered another setback in July when a buyer backed out of a $28.9 million contract (thereby forfeiting a $600,000 deposit). Our 2008 earnings estimate is at the low end of ALLETE's targeted range of $2.70-$2.90 a share.

We expect a partial earnings recovery in 2009. Even if the real estate business doesn't show much (if any) improvement, the company's retail and wholesale utility operations should benefit from a full year of rate relief. (A $7.5 million wholesale tariff hike took effect at the start of March of this year.) Moreover, Minnesota Power has regulatory mechanisms that enable it to recover about half of its capital spending via rate riders, even before these expenditures are rolled into base rates.

An asset acquisition is pending. Minnesota Power has agreed to pay $80 million for a transmission line in early 2009. This will enable the utility to add wind capacity and help it to comply with a state mandate regarding renewable energy.

We have a neutral opinion of this stock. Its yield and 3- to 5-year total return potential are about average, compared with the norms for the broader industry.

Paul E. Debbas, CFA *September 26, 2008*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢ net; '05, ($1.84); gain (losses) on discontinued operations: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '07: $2.49/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '95: 11.6%; earned on avg. com. eq., '07: 12.4%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	NMF

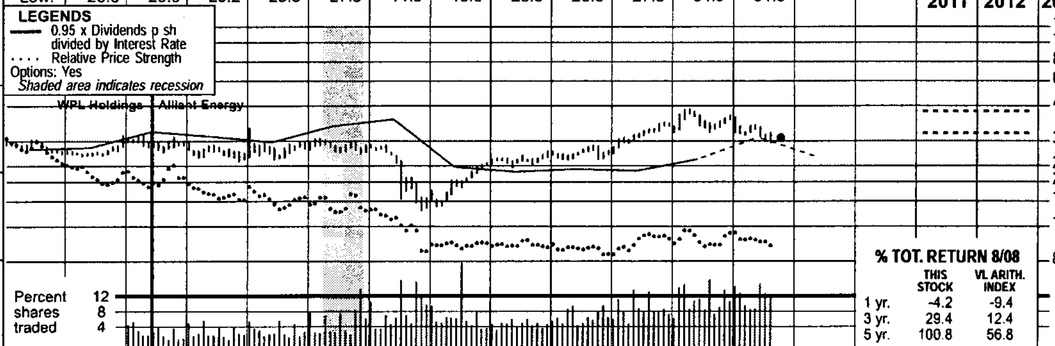
ALLIANT ENERGY NYSE-LNT

RECENT PRICE	33.31	P/E RATIO	11.9 (Trailing: 11.6 Median: 14.0)	RELATIVE P/E RATIO	0.78	DIV'D YLD	4.4%	VALUE LINE

TIMELINESS 3 Raised 2/15/08
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Raised 8/1/08
BETA .80 (1.00 = Market)

High:	34.4	34.9	32.4	37.8	33.2	31.0	25.1	28.8	30.6	40.0	46.5	42.4
Low:	26.8	28.0	25.2	25.8	27.5	14.3	15.0	23.5	25.6	27.5	34.9	31.3

Target Price Range
2011 | 2012 | 2013



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+35%)	*12%*
Low	35	(+5%)	*6%*

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	1	0
Options	1	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	116	122	113
to Sell	108	115	114
Hld's(000)	63027	63707	64598

% TOT. RETURN 8/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-4.2	-9.4
3 yr.	29.4	12.4
5 yr.	100.8	56.8

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share. Data prior to 1998 are for WPL Holdings only and are not comparable with Alliant Energy data.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
27.45	27.83	30.44	30.97	28.26	28.19	25.56	28.02	28.93	31.15	***33.70***	***34.45***	Revenues per sh	***39.85***
4.85	5.71	6.57	5.82	4.52	4.19	4.69	5.46	4.33	5.12	***5.55***	***6.10***	"Cash Flow" per sh	***7.55***
1.26	2.19	2.47	2.42	1.18	1.57	1.85	2.21	2.06	2.69	***2.75***	***2.90***	Earnings per sh A	***3.30***
2.00	2.00	2.00	2.00	2.00	1.00	1.02	1.05	1.15	1.27	***1.40***	***1.53***	Div'd Decl'd per sh B ■ †	***1.92***
4.79	6.06	13.50	9.13	7.12	7.69	5.55	4.51	3.42	4.91	***9.45***	***11.00***	Cap'l Spending per sh	***5.90***
20.69	27.29	25.79	21.39	19.89	21.37	22.13	20.85	22.83	24.30	***25.75***	***27.15***	Book Value per sh C	***31.95***
77.63	78.98	79.01	89.68	92.30	110.96	115.74	117.04	116.13	110.36	***111.00***	***112.00***	Common Shs Outst'g D	***119.00***
25.1	13.0	11.8	12.6	19.9	12.7	14.0	12.6	16.8	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	***13.0***
1.31	.74	.77	.65	1.09	.72	.74	.67	.91	.80	*Value Line*		Relative P/E Ratio	***.85***
6.3%	7.0%	6.9%	6.6%	8.5%	5.0%	3.9%	3.8%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	***4.4%***
2130.9	2198.0	2405.0	2777.3	2608.8	3128.2	2958.7	3279.6	3359.4	3437.6	***3740***	***3970***	Revenues ($mill)	***4740***
103.4	178.2	203.1	194.9	113.1	176.6	229.5	337.8	260.1	320.8	***325***	***340***	Net Profit ($mill)	***410***
36.0%	40.3%	54.0%	23.5%	24.2%	28.9%	26.7%	19.0%	43.8%	44.4%	***44.0%***	***36.0%***	Income Tax Rate	***44.0%***
6.6%	4.1%	4.3%	5.7%	6.8%	11.7%	8.1%	3.0%	3.1%	2.4%	***3.0%***	***3.0%***	AFUDC % to Net Profit	***3.0%***
47.3%	39.6%	47.0%	54.7%	56.4%	44.8%	45.0%	41.6%	31.4%	32.4%	***36.5%***	***40.0%***	Long-Term Debt Ratio	***41.0%***
49.2%	57.4%	50.2%	42.7%	39.2%	50.0%	50.2%	53.1%	62.9%	61.9%	***58.5%***	***55.5%***	Common Equity Ratio	***55.5%***
3262.9	3756.0	4061.4	4490.2	4679.1	4738.4	5104.7	4599.1	4218.4	4329.5	***4905***	***5485***	Total Capital ($mill)	***6850***
3101.7	3486.0	3719.3	3862.8	3729.2	4432.6	5284.6	4866.2	4944.9	4679.9	***5420***	***6290***	Net Plant ($mill)	***8380***
4.9%	6.1%	6.6%	6.2%	4.1%	5.7%	6.1%	8.9%	7.5%	8.6%	***8.0%***	***7.5%***	Return on Total Cap'l	***7.5%***
6.0%	7.9%	9.4%	9.6%	5.5%	6.8%	8.2%	12.6%	9.0%	11.0%	***10.5%***	***10.5%***	Return on Shr. Equity	***9.5%***
6.0%	8.0%	9.6%	9.8%	5.8%	6.7%	8.2%	13.1%	9.1%	11.3%	***11.5%***	***10.5%***	Return on Com Equity E	***10.0%***
NMF	.7%	1.9%	1.6%	NMF	2.5%	3.8%	8.1%	4.0%	5.9%	***5.0%***	***5.0%***	Retained to Com Eq	***4.5%***
NMF	92%	81%	85%	NMF	67%	58%	42%	59%	50%	***54%***	***55%***	All Div'ds to Net Prof	***60%***

CAPITAL STRUCTURE as of 6/30/08
Total Debt $1748.8 mill. **Due in 5 Yrs** $651.5 mill.
LT Debt $1403.2 mill. **LT Interest** $99.0 mill.
(LT interest earned: 6.6x)
Pension Assets-12/07 $890.0 mill. **Oblig.** $879.0 mill.
Pfd Stock $243.8 mill. **Pfd Div'd** $18.7 mill.
449,765 shs. $100 par; 8,199,460 shs. $25 par; 1,127,787 shs. $50 par.

Common Stock 110,450,391 shs. **as of 7/31/08**
MARKET CAP: $3.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+4.6	-1.7	+1.8
Avg. Indust. Use (MWH)	4215	4180	4282
Avg. Indust. Revs. per KWH (¢)	5.26	5.96	5.77
Capacity at Peak (Mw)	5446	4985	4902
Peak Load, Summer (Mw)	5932	5987	5751
Annual Load Factor (%)	55.6	52.0	53.0
% Change Customers (yr-end)	+1.3	+1.8	-1.8
Fixed Charge Cov. (%)	252	350	416

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '05-'07 to '11-'13**
Revenues	--	-.5%	*5.0%*
"Cash Flow"	-.5%	-2.5%	*7.0%*
Earnings	.5%	3.0%	*6.0%*
Dividends	-5.0%	-10.5%	*9.0%*
Book Value	1.5%	.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	825.2	686.7	860.9	906.8	3279.6
2006	930.9	696.8	890.4	841.3	3359.4
2007	912.7	746.2	907.3	871.4	3437.6
2008	992.0	827.4	***980***	***940.6***	***3740***
2009	***1050***	***880***	***1040***	***1000***	***3970***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.23	.41	1.05	.52	2.21
2006	.56	.39	.75	.36	2.06
2007	.56	.43	1.05	.65	2.69
2008	.62	.55	***1.00***	***.58***	***2.75***
2009	***.67***	***.58***	***1.05***	***.60***	***2.90***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.25	.25	.25	.263	1.01
2005	.263	.263	.263	.263	1.05
2006	.288	.288	.288	.288	1.15
2007	.318	.318	.318	.318	1.27
2008	.35	.35	.35		

BUSINESS: Alliant Energy, formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies elect. (73% of revs.), gas (19%), and other services (8%) in Wisconsin, Iowa, Minnesota, & Illinois. Elect. revs. by state: WI, 47%; IA, 49%; MN, 3%; IL, 1%. Elect. rev.: resid., 35%; comm'l, 22%; ind'l, 30%; wholesale, 7%; other, 6%. Fuel sources, '07: coal, 65%; gas. 28%; oil, 6%; other, under 1%. Fuel costs: 54% of revs. '07 deprec. rate: 2.6%. Est'd plant age: 10 yrs. Has 5,179 empls., Chrmn.: Erroll B. Davis, Jr. Pres. & CEO: William D. Harvey. Inc.: WI. Address: 4902 N. Biltmore Lane, P.O. Box 77007, Madison, WI 53707-1007. Tel.: 608-458-3391. Internet: www.alliant-energy.com.

Alliant Energy seeks higher rates in Wisconsin. The request calls for a $93 million boost in retail electric rates and a small decrease of $814,000 in natural gas tariffs. The hike would cover the $180 million cost of the 68-megawatt (mw) Cedar Ridge wind farm, the addition of emission controls on existing plants, and expansion of the energy conservation and renewable power programs. The filing also includes recovery of transmission and distribution costs. It is based on no change in the current 10.8% allowed return on equity. Whatever amount is awarded will take effect on January 1, 2009. Finally, the application asks that the case be reopened later to include costs associated with approved infrastructure additions for 2010.

The company plans two new coal-fired plants. It recently received approval to build the 630-mw Sutherland 4 unit, for which it will pay $950 million for a 350-mw stake. Consent was granted subject to the requirement that 10% of the facility's output would be generated from biomass sources within five years of operation. LNT also wants to build a 300-mw plant at the existing Nelson Dewey site, since its location in the transmission system would allow increased imports into Wisconsin of 400 mw to 600 mw. But the commission's staff recommends rejection of the plant because of its high estimated cost of $1.1 billion. The full commission's decision on the project is due by yearend.

The timing of cost recovery from last June's flooding damage will have an important bearing on 2008 earnings. LNT estimates the storms will reduce this year's earnings by $0.20 a share. The impact will be mitigated by insurance proceeds, recoupment of steam costs under a renegotiated contract, and deferral requests submitted to regulators. Though reasonable recovery is likely, it's uncertain whether it will all be achieved this year. For now, we are maintaining our 2008 earnings estimate of $2.75 a share. Higher rates point to improved results next year.

The yield is near the industry norm. But a low payout ratio and projected solid earnings gains to 2011-2013 suggest above-average dividend growth over the same time frame. The stock might interest income-oriented investors.

Arthur H. Medalie *September 26, 2008*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '96, net 7¢; '99, 32¢; '00, $2.56; '01, (28¢); '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 84¢; '07, $1.11. Next egs. rpt. due late Oct. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov.. ■ Div'd reinvest. plan avail. † shareholder invest. plan avail. (C) Incl. deferred chgs. in '07: $307.9 mill., $2.79/sh. (D) In mill. (E) Rate base: Orig. cost. Rate allowed on com. eq.: in '05, WI, 10.8%; in '07, IA., 10.7%; earned on avg. com. eq., '07: 11.3%. Regul. Clim.: WI, Above Avg.; IA, Below Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	60

AMEREN NYSE-AEE

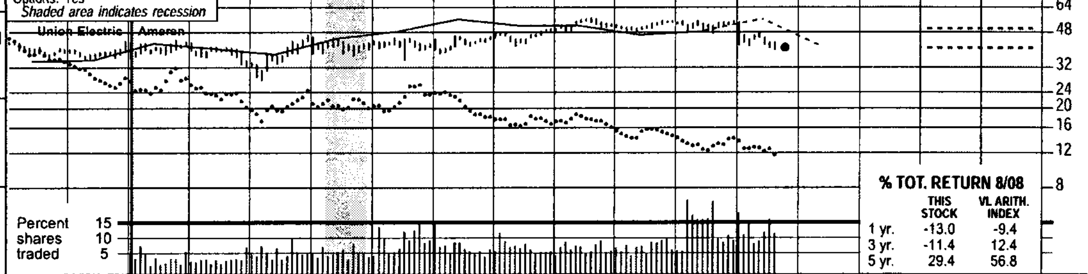
RECENT PRICE	40.42	P/E RATIO	12.9 (Trailing: 12.2 Median: 15.0)	RELATIVE P/E RATIO	0.85	DIV'D YLD	6.3%	VALUE LINE

TIMELINESS **3** Raised 8/24/07
SAFETY **2** Lowered 3/30/07
TECHNICAL **3** Raised 8/15/08
BETA .80 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	43.8	44.3	42.9	46.9	46.0	45.3	46.5	50.4	56.8	55.2	55.0	54.3
Low:	34.5	35.6	32.0	27.6	36.5	34.7	37.4	40.6	47.5	48.0	47.1	38.7

Target Price Range 2011 | 2012 | 2013

LEGENDS
— 0.88 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	11%
Low	40	(Nil)	6%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	162	156	163
to Sell	164	179	142
Hld's(000)	133717	124249	124375

Percent shares traded 15 10 5

% TOT. RETURN 8/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-13.0	-9.4
3 yr.	-11.4	12.4
5 yr.	29.4	56.8

Ameren was formed on December 31, 1997 through the merger of Union Electric and CIPSCO. Each common share of Union Electric was exchanged for 1.00 share of Ameren, while each common share of CIPSCO was exchanged for 1.03 Ameren shares.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
24.18	25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.15	37.30	38.60	Revenues per sh	41.75
5.36	5.36	6.11	6.33	5.28	6.29	5.57	6.10	5.79	6.17	6.70	7.20	"Cash Flow" per sh	8.40
2.82	2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	3.34	3.10	3.25	Earnings per sh A	3.55
2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	Div'd Decl'd per sh B■	2.54
2.37	4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.80	6.62	7.60	7.55	Cap'l Spending per sh	7.20
22.27	22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.35	33.20	34.05	Book Value per sh C	37.40
137.22	137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.73	210.40	212.00	Common Shs Outst'g E	222.00
14.2	13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	15.6	Bold figures are		Avg Ann'l P/E Ratio	12.0
.74	.77	.72	.62	.86	.77	.86	.89	1.05	.83	Value Line		Relative P/E Ratio	.80
6.3%	6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	estimates		Avg Ann'l Div'd Yield	6.0%
3318.2	3523.6	3855.8	4505.9	3841.0	4593.0	5160.0	6780.0	6880.0	7546.0	7830	8180	Revenues ($mill)	9270
399.1	397.8	469.8	481.0	393.0	517.0	541.0	628.0	547.0	629.0	660	695	Net Profit ($mill)	795
40.1%	39.4%	39.1%	38.4%	38.9%	36.8%	34.3%	35.6%	35.8%	33.5%	34.0%	34.0%	Income Tax Rate	34.0%
3.0%	3.6%	2.9%	4.3%	2.8%	1.9%	1.8%	2.9%	.7%	1.4%	3.0%	3.0%	AFUDC % to Net Profit	3.0%
41.0%	42.4%	44.4%	44.2%	46.0%	47.3%	45.5%	44.9%	43.8%	45.0%	49.5%	49.5%	Long-Term Debt Ratio	49.0%
54.8%	53.5%	51.8%	52.2%	51.4%	50.6%	52.6%	53.3%	54.6%	53.4%	49.0%	49.0%	Common Equity Ratio	50.0%
5580.7	5773.4	6176.9	6419.3	7468.0	8606.0	11036	11932	12063	12638	14280	14730	Total Capital ($mill)	16615
6928.0	7165.2	7705.7	8426.6	8914.0	10917	13297	13572	14286	15069	15910	16670	Net Plant ($mill)	18470
8.7%	8.2%	8.9%	8.7%	6.5%	7.4%	6.0%	6.5%	5.7%	6.2%	6.0%	6.0%	Return on Total Cap'l	6.0%
12.1%	12.0%	13.7%	13.4%	9.7%	11.4%	9.0%	9.5%	8.1%	9.1%	9.0%	9.5%	Return on Shr. Equity	9.5%
12.6%	12.5%	14.3%	14.0%	9.9%	11.6%	9.1%	9.7%	8.1%	9.0%	9.5%	9.5%	Return on Com Equity D	9.5%
1.2%	1.2%	3.4%	3.6%	.2%	2.2%	.9%	1.7%	.2%	1.2%	1.5%	2.0%	Retained to Com Eq	2.5%
90%	91%	77%	75%	98%	81%	91%	83%	97%	86%	82%	78%	All Div'ds to Net Prof	72%

CAPITAL STRUCTURE as of 6/30/08
Total Debt $7881.0 mill. Due in 5 Yrs $2650.0 mill.
LT Debt $6146.0 mill. LT Interest $335.8 mill.

(LT interest earned: 4.2x)

Pension Assets-12/07 $2.70 bill. Oblig. $3.08 bill.

Pfd Stock $211.0 mill. Pfd Div'd $11.0 mill.
1,137,595 shs. $3.50 to $7.64 cum. (no par), stated at liquid. value; 191,204 shs., $100 par, 4.50% to to 4.60%; 800,000 shs. 4.00% to 6.625%.

Common Stock 210,208,319 shs. as of 7/31/08

MARKET CAP: $8.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+15.0	+4.5	+6.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.27	4.25	4.03
Capacity at Peak (Mw)	20888	21177	21150
Peak Load, Summer (Mw)	17563	16416	16580
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	377	294	280

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	4.5%	3.5%	3.5%
"Cash Flow"	1.5%	.5%	5.5%
Earnings	1.0%	-.5%	3.5%
Dividends	--	--	Nil
Book Value	3.5%	5.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1621	1590	1868	1701	6780.0
2006	1800	1550	1910	1620	6880.0
2007	2019	1723	1997	1807	7546.0
2008	2079	1788	2080	1883	7830
2009	2170	1880	2160	1970	8180

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.62	.93	1.37	.21	3.13
2006	.34	.60	1.42	.30	2.66
2007	.68	.69	1.36	.61	3.34
2008	.66	.67	1.35	.42	3.10
2009	.70	.70	1.40	.45	3.25

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.635	.635	.635	.635	2.54
2005	.635	.635	.635	.635	2.54
2006	.635	.635	.635	.635	2.54
2007	.635	.635	.635	.635	2.54
2008	.635	.635			

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 2003; Illinois Power 2004. Supplies elect. and gas to 3,400,000 customers in Missouri (40% elect. revs.) and Illinois (60%). Elect. revs.: resid., 42%; commer., 36%; indust., 17%; other, 5%. Largest indust. customers: primary metals, chemicals, transportation equipment, petroleum refining. 2007 fuels: coal, 84%; nuclear, 12%; other, 4%. Fuel costs, 46% of revenues; labor costs, 12%. 2007 depreciation rate: 3%-4%. Estimated plant age: 13 years. Has 9,069 employees. Chrmn., CEO, and Pres.: Gary L. Rainwater. Inc.: Missouri. Address: 1901 Chouteau Street, St. Louis, Missouri 63166. Telephone: 314-621-3222. Internet: www.ameren.com.

Ameren awaits regulatory orders on rate filings in two states. In Missouri, it seeks an increase of $251 million annually. The hike would cover the $500 million cost to reduce emissions at coal-fired plants, enable the company to put vulnerable transmission lines underground, and offset the rising price of buying and transporting coal. AEE also asks for a fuel and purchased-power recovery mechanism without the expense of a full-blown rate case. An order here is due in March. The Illinois subsidiary has requested higher electric rates of $180 million and $67 million in increased posted gas tariffs. The boost is necessary to cover the planned $900 million outlay for improvements to the system through 2010. But a state legislator and consumer watchdogs are resisting the increase. Whatever amount is granted will take effect next month.

The company is expanding its energy efficiency programs. In 2009, it will spend $24 million to delay the need for new power plants. By 2015, it will increase the outlay to $56 million yearly. That should lower demand growth by 25% by 2016. The program was developed with input from consumer and environmental groups. Even with reduced energy usage, however, AEE will require new baseload facilities by 2018. That's largely because of the expected retirement of some old and costly coal-fired facilities. Meanwhile, peaking units are being added to maintain a satisfactory reserve margin.

Earnings may decline this year. The big negative is higher fuel costs, which will reduce net by $0.40 a share. Too, the issuance of long-term debt to pay for pollution controls and improvements to the infrastructure has increased interest expense. Moreover, nonregulated business operations may post only flat results for another few years. Despite a full year of higher rates in two jurisdictions, we estimate 2008 earnings will drop 7%, to $3.10 a share. Two pending rate orders suggest better results in 2009.

These shares are an average utility selection. The yield is almost two percentage points above the group average. But the directors haven't raised the payout since 1997, and we don't expect them to do so in the coming 3 to 5 years.

Arthur H. Medalie *September 26, 2008*

(A) EPS basic. Excl. nonrecur. gain, (loss): '03, 11¢; '05, (11¢). Next egs. report due late Oct. (B) Div'ds historically paid in late March, late June, late Sept., and late Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred chgs. in '07, $4.94/sh. (D) Rate base: orig. cost depreciated. Rate allowed in MO on common equity in '97: 10.25%; earned on average com. eq. in '07: 9.3%. Regul. Clim.: Average. (E) In millions.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	80

EXELON CORP. NYSE-EXC

RECENT PRICE **51.12** | P/E RATIO **12.7** (Trailing: 13.1; Median: NMF) | RELATIVE P/E RATIO **1.25** | DIV'D YLD **4.2%** | VALUE LINE

TIMELINESS	4 Lowered 11/7/08
SAFETY	1 Raised 6/3/05
TECHNICAL	3 Raised 11/21/08
BETA .90 (1.00 = Market)	

2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+75%)	18%
Low	75	(+45%)	13%

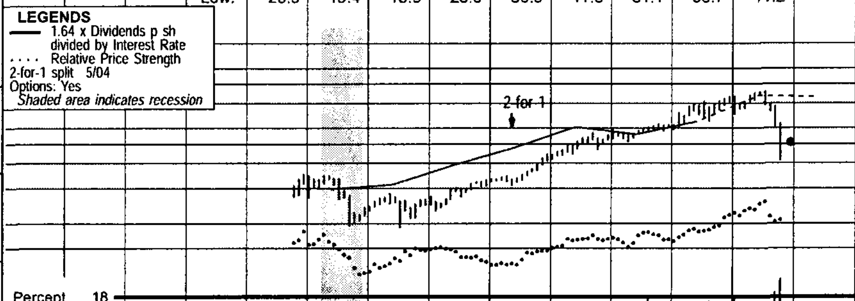
Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	1	0
Options	11	3	0	0	3	0	0	2	0
to Sell	0	4	0	0	3	0	0	2	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	366	340	338
to Sell	278	333	339
Hld's(000)	442191	434572	428412

	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	35.5	35.1	28.5	33.3	44.9	57.5	63.6	86.8	92.1
Low:	26.9	19.4	18.9	23.0	30.9	41.8	51.1	58.7	41.2



Target Price Range

2011 | 2012 | 2013

% TOT. RETURN 10/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-32.9	-38.0
3 yr.	12.8	-17.7
5 yr.	98.0	4.8

Exelon Corp. was formed on October 20, 2000 upon a merger of equals between PECO Energy Co. and Unicom Corp. (Unicom was the holding company for Commonwealth Edison Co.) PECO Energy stockholders received one common share in Exelon for each common share held. Unicom investors exchanged each of their common shares for .875 of an Exelon share and $3.00 in cash. Data in 2000 reflect PECO Energy and the addition of Unicom as of October 20th.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
--	19.40	11.75	23.58	23.13	23.89	21.85	23.06	23.37	28.62	*28.90*	*30.45*	Revenues per sh	*39.00*
--	3.55	1.84	5.06	5.03	5.02	5.68	6.19	6.71	7.43	*7.60*	*7.75*	"Cash Flow" per sh	*9.75*
--	1.86	1.39	2.20	2.40	2.44	2.75	3.21	3.50	4.03	*4.05*	*4.15*	Earnings per sh A	*5.75*
--	--	--	.91	.88	.96	1.26	1.60	1.64	1.82	*2.05*	*2.15*	Div'd Decl'd per sh B ■	*2.40*
--	--	1.18	3.18	3.33	2.95	2.89	3.25	3.61	4.05	*4.75*	*5.00*	Cap'l Spending per sh	*6.25*
--	--	11.31	12.82	11.97	12.84	14.19	13.70	14.89	15.34	*16.90*	*18.90*	Book Value per sh C	*24.50*
--	630.20	638.01	642.01	646.63	662.00	664.20	666.00	670.00	661.00	*657.00*	*657.00*	Common Shs Outst'g D	*630.00*
--	--	22.4	13.2	10.5	11.8	13.0	15.4	16.5	18.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
--	--	1.46	.68	.57	.67	.69	.82	.89	.97	*estimates*		Relative P/E Ratio	*.95*
--	--	--	3.1%	3.5%	3.4%	3.5%	3.2%	2.8%	2.5%			Avg Ann'l Div'd Yield	*3.0%*
--	12225	7499.0	15140	14955	15812	14515	15357	15655	18916	*19000*	*20000*	Revenues ($mill)	*24500*
--	1233.0	590.0	1465.0	1599.0	1641.0	1844.0	2162.0	2370.0	2730.0	*2695*	*2750*	Net Profit ($mill)	*3760*
--	35.5%	36.6%	38.9%	36.7%	32.9%	27.5%	30.4%	33.7%	34.6%	*33.5%*	*37.0%*	Income Tax Rate	*37.0%*
--	--	.5%	1.2%	1.2%	1.9%	.9%	1.0%	1.6%	1.8%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
--	35.5%	62.3%	59.3%	61.2%	61.1%	56.1%	56.1%	54.2%	53.9%	*54.0%*	*50.5%*	Long-Term Debt Ratio	*48.0%*
--	10.1%	34.7%	37.9%	36.1%	38.5%	43.5%	43.5%	45.4%	45.7%	*45.5%*	*49.0%*	Common Equity Ratio	*52.0%*
--	--	20803	21719	21464	22079	21658	20972	21971	22189	*24425*	*25300*	Total Capital ($mill)	*29800*
--	--	12936	13742	17134	20630	21482	21981	22775	24153	*25775*	*27425*	Net Plant ($mill)	*33000*
--	--	4.1%	9.0%	9.4%	9.2%	10.4%	12.1%	12.5%	14.1%	*12.5%*	*12.5%*	Return on Total Cap'l	*14.0%*
--	--	7.5%	16.6%	19.2%	19.1%	19.4%	23.5%	23.6%	26.7%	*24.0%*	*22.0%*	Return on Shr. Equity	*24.0%*
--	--	7.8%	17.2%	20.1%	18.8%	19.5%	23.6%	23.7%	26.9%	*24.0%*	*22.0%*	Return on Com Equity E	*24.5%*
--	--	7.8%	10.1%	12.8%	11.5%	10.7%	11.9%	13.0%	15.3%	*12.0%*	*10.5%*	Retained to Com Eq	*14.5%*
--	--	4%	43%	38%	40%	45%	50%	45%	43%	*50%*	*52%*	All Div'ds to Net Prof	*41%*

CAPITAL STRUCTURE as of 6/30/08
Total Debt $14754 mill. **Due in 5 Yrs** $6892 mill.
LT Debt $12641 mill. **LT Interest** $695 mill.
Includes $1548 mill. nonrecourse transition bonds.
(LT interest earned: 6.0x)
Leases, Uncapitalized Annual rentals $69.0 mill.
Pension Assets-12/07 $9.63 bill. **Oblig.** $10.4 bill.
Pfd Stock $87.0 mill. **Pfd Div'd** $4.0 mill.
Includes $87.0 mill. in preferred securities of subsidiaries.
Common Stock 657,332,170 shs.

MARKET CAP: $34 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+4.9	-1.7	+3.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.84	7.05	8.34
Capacity at Peak (Mw)	33520	33464	NA
Peak Load (Mw)	30261	32545	30521
Nuclear Capacity Factor (%)	93.5	93.9	94.5
% Change Customers (yr-end)	+.7	+1.1	+.9
Fixed Charge Cov. (%)	461	466	516

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	--	5.0%	7.5%
"Cash Flow"	--	11.0%	6.0%
Earnings	--	12.5%	8.0%
Dividends	--	23.0%	6.5%
Book Value	--	4.0%	9.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2005	3561	3484	4473	3839	15357
2006	3861	3697	4401	3696	15655
2007	4829	4501	5032	4554	18916
2008	4517	4622	5228	*4633*	*19000*
2009	*4800*	*4800*	*5600*	*4800*	*20000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2005	.77	.76	1.07	.61	3.21
2006	.59	.95	1.09	.87	3.50
2007	1.01	1.03	1.15	.84	4.03
2008	.88	1.13	1.06	*.98*	*4.05*
2009	*1.00*	*1.00*	*1.15*	*1.00*	*4.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.275	.275	.305	.40	1.26
2005	.40	.40	.40	.40	1.60
2006	.40	.40	.40	.40	1.60
2007	.44	.44	.44	.44	1.76
2008	.50	.50	.50	.525	

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, which serves 3.8 million electric customers in Illinois, and PECO Energy, which serves 1.6 million electric and 481,000 gas customers in Pennsylvania. Markets energy in the mid-Atlantic and Midwest regions. Electric revenue breakdown, '07: residential, 47%; small commercial & industrial, 27%; large commercial & industrial, 17%; other, 9%. Generating sources, '07: nuclear, 74%; other, 6%; purchased, 20%. Fuel costs: 40% of revenues. '07 deprec. rate: 6.8%. Has 17,800 employees. Chairman & CEO: John W. Rowe. President & COO: Christopher Crane. Inc.: PA. Address: 10 South Dearborn St., P.O. Box 805398, Chicago, IL 60680-5398. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon made an unsolicited takeover bid for NRG, which rejected the offer. Exelon offered .485 of a share for each NRG share, for a total of around $6 billion in stock. Exelon believes that NRG's nonregulated, low-cost generating assets (mostly coal) would enhance its geographic diversity. The transaction wouldn't have much effect on earnings but would boost cash flow. Although NRG rejected Exelon's bid, we would not rule out the possibility of a sweetened offer. Our figures do not assume an acquisition.

Business conditions have worsened. The turmoil in the credit markets has affected the wholesale power markets, and power prices have declined. In fact, one of the credit-rating agencies lowered Exelon's ratings last month. Also, operating and maintenance expenses are rising, especially for nuclear power. At this point, it appears as if earnings will be flattish in 2008. We have reduced our 2009 share-net forecast from $4.30 to $4.15, not much above the 2008 estimate, and expect no sizable bottom-line improvement until 2011. As a result of the increased uncertainty, Exelon has suspended its $1.5 billion stock-buyback program, despite the fact that its stock has fallen more than 25% since our August report. The board of directors did increase the quarterly dividend by $0.025 a share (5%), however.

Commonwealth Edison has received a rate increase. The Illinois commission granted the utility a tariff hike of $273.6 million, based on a return of 10.3% on a common-equity ratio of 45.04%. New rates took effect in mid-September.

A settlement on PECO Energy's gas rate request was approved. The utility had sought an increase of $98.3 million (11.2%). The Pennsylvania commission approved a settlement calling for a boost of $76.5 million (8.7%). No return on equity was specified. New tariffs will take effect at the start of 2009.

This high-quality stock offers investors 3- to 5-year total return potential that's superior to that of the average power equity, especially on a risk-adjusted basis. Exelon has an attractive fleet of generating assets that gives the company good long-term prospects, whether or not it winds up with NRG.

Paul E. Debbas, CFA *November 28, 2008*

(A) Diluted earnings. Excludes nonrecurring gains (losses): '01, 2¢; '02, (18¢); '03, ($1.06); '04, 3¢ net; '05, ($1.85) net; '06, ($1.15); gain from discontinued operations: '07, 2¢. Next earnings report due late January. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment program available. (C) Incl. deferred charges. In '07: $11.74/sh. (D) In mill., adj. for split. (E) Rate allowed on com. eq. in IL in '08: 10.3%; earned on avg. com. eq., '07: 26.7%. Regulatory Climate: PA, Average; IL, Below Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	90

FIRSTENERGY NYSE-FE

RECENT PRICE 54.00 | P/E RATIO 11.3 (Trailing: 13.0 / Median: 14.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 5/5/06
SAFETY 2 Raised 6/2/06
TECHNICAL 3 Raised 11/21/08
BETA .85 (1.00 = Market)

High:	29.0	34.1	33.2	32.1	37.0	39.1	38.9	43.4	53.4	61.7	75.0	84.0
Low:	19.3	27.1	22.1	18.0	25.1	24.8	25.8	35.2	37.7	47.8	57.8	41.2

Target Price Range
2011 | 2012 | 2013

2011-13 PROJECTIONS

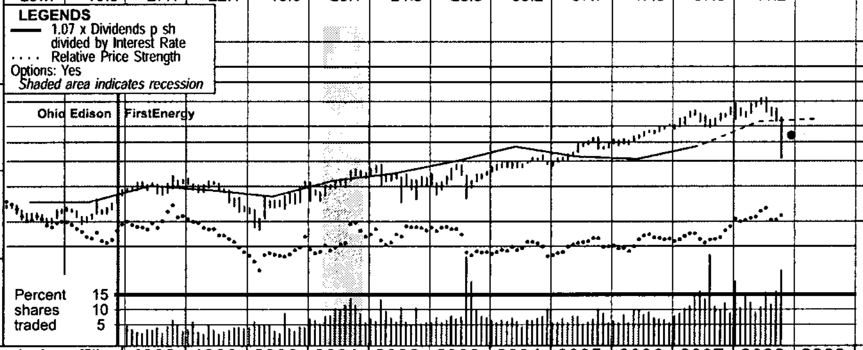
	Price	Gain	Ann'l Total Return
High	100	(+85%)	*20%*
Low	75	(+40%)	*12%*

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	2	0	21	1	2	3	1	0	0
to Sell	2	0	17	8	4	3	0	0	1

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	227	217	221
to Sell	189	210	223
Hld's(000)	218058	221509	221857



% TOT. RETURN 10/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-22.9	-38.0
3 yr.	21.0	-17.7
5 yr.	80.6	4.8

FirstEnergy was formed through the affiliation of Ohio Edison Company and Centerior Energy in November of 1997. Ohio Edison stockholders received one share of FirstEnergy for every Ohio Edison share, and Centerior stockholders received .52 of a FirstEnergy share for each Centerior share. In November of 2001, FirstEnergy acquired GPU. GPU holders received $40 in cash or stock for each GPU share.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
24.72	27.19	31.31	26.88	40.83	37.31	37.76	36.35	36.03	42.00	*44.80*	*48.55*	Revenues per sh	*59.00*
5.33	6.89	7.28	5.48	6.45	4.79	7.60	7.55	7.22	8.34	*9.05*	*10.05*	"Cash Flow" per sh	*11.75*
1.95	2.50	2.69	2.84	2.54	1.47	2.77	2.84	3.82	4.22	*4.30*	*4.95*	Earnings per sh A	*6.50*
1.50	1.50	1.50	1.50	1.50	1.50	1.91	1.71	1.85	2.05	*2.25*	*2.45*	Div'd Decl'd per sh B ■	*3.05*
2.75	2.69	2.74	2.86	3.35	2.60	2.57	3.66	4.12	5.36	*7.10*	*5.80*	Cap'l Spending per sh	*5.25*
18.77	19.63	20.72	24.86	23.92	25.13	26.04	27.86	28.30	29.45	*31.30*	*33.80*	Book Value per sh C	*43.25*
237.07	232.45	224.53	297.64	297.64	329.84	329.84	329.84	319.21	304.84	*304.85*	*304.85*	Common Shs Outst'g D	*304.85*
15.4	11.3	9.2	10.9	13.0	22.5	14.1	16.1	14.2	15.6	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.80	.64	.60	.56	.71	1.28	.74	.86	.77	.83	*Value Line*		Relative P/E Ratio	*.90*
5.0%	5.3%	6.1%	4.8%	4.6%	4.5%	4.9%	3.7%	3.4%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*
5861.3	6319.6	7029.0	7999.4	12152	12307	12453	11989	11501	12802	*13650*	*14800*	Revenues ($mill)	*18000*
507.2	644.8	661.7	727.0	827.6	490.8	932.6	951.0	1265.0	1309.0	*1310*	*1510*	Net Profit ($mill)	*1995*
38.8%	38.0%	36.3%	39.5%	41.5%	43.9%	42.2%	42.1%	38.6%	40.3%	*37.0%*	*38.0%*	Income Tax Rate	*40.0%*
1.5%	2.1%	4.1%	4.9%	3.0%	6.5%	2.7%	2.0%	2.1%	2.4%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
54.0%	52.3%	52.3%	60.1%	60.2%	53.1%	52.8%	46.5%	48.6%	49.7%	*49.0%*	*48.5%*	Long-Term Debt Ratio	*46.5%*
37.8%	39.8%	41.5%	37.2%	38.0%	45.0%	45.4%	52.4%	51.4%	50.3%	*51.0%*	*51.5%*	Common Equity Ratio	*53.5%*
11756	11470	11205	19907	18756	18414	18938	17527	17570	17846	*18825*	*20025*	Total Capital ($mill)	*24600*
9242.6	9093.3	7575.1	12428	12680	13269	13478	13998	14667	15383	*16350*	*16525*	Net Plant ($mill)	*16800*
6.4%	7.8%	7.9%	4.9%	6.3%	4.6%	6.5%	7.1%	9.0%	9.0%	*8.5%*	*9.0%*	Return on Total Cap'l	*9.5%*
9.4%	11.8%	12.4%	9.2%	11.1%	5.7%	10.4%	10.1%	14.0%	14.6%	*14.0%*	*14.5%*	Return on Shr. Equity	*15.0%*
9.9%	12.5%	12.9%	8.9%	10.5%	5.4%	10.6%	10.2%	13.9%	14.6%	*14.0%*	*14.5%*	Return on Com Equity E	*15.0%*
2.3%	5.0%	5.7%	4.3%	4.3%	NMF	4.9%	4.2%	7.4%	7.7%	*6.5%*	*7.5%*	Retained to Com Eq	*8.0%*
80%	65%	60%	56%	63%	101%	55%	59%	47%	47%	*52%*	*49%*	All Div'ds to Net Prof	*47%*

CAPITAL STRUCTURE as of 3/31/08
Total Debt $12164 mill. **Due in 5 Yrs** $6212.0 mill.
LT Debt $8332.0 mill. **LT Interest** $500.0 mill.
Incl. $284.8 mill. 9% ($25 par) cumulative mandatorily redeemable preferred securities.
(LT interest earned: 4.6x)

Leases, Uncapitalized Annual rentals $316.0 mill.
Pension Assets-12/07 $5.29 bill. **Oblig.** $4.75 bill.

Pfd Stock None

Common Stock 304,835,407 shs.
as of 5/8/08
MARKET CAP: $16 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+5.2	+6.7	+2.0
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	62.1	NA	NA
% Change Customers (yr-end)	+.8	+.5	+1.0
Fixed Charge Cov. (%)	299	355	363

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	10.0%	3.0%	*7.5%*
"Cash Flow"	6.5%	4.0%	*7.5%*
Earnings	6.0%	6.0%	*10.0%*
Dividends	2.0%	4.5%	*8.5%*
Book Value	5.5%	4.5%	*7.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	2750	2843	3504	2892	11989
2006	2705	2751	3365	2680	11501
2007	2973	3109	3641	3079	12802
2008	3277	3245	3904	*3224*	*13650*
2009	*3500*	*3600*	*4200*	*3500*	*14800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.42	.76	1.01	.65	2.84
2006	.67	.93	1.40	.84	3.82
2007	.92	1.10	1.34	.87	4.22
2008	.90	.85	1.54	*1.01*	*4.30*
2009	*1.10*	*1.15*	*1.60*	*1.10*	*4.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.375	.375	.375	.375	1.50
2005	.413	.413	.413	.43	1.67
2006	.45	.45	.45	.45	1.80
2007	.50	.50	.50	.50	2.00
2008	.55	.55	.55		

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, and Jersey Central Power & Light. Provides electric service to 4.5 million customers in Ohio (58% of revenues), New Jersey (22%) and Pennsylvania (20%). Electric revenue breakdown by customer class not provided by company. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 39% of revenues. '07 reported deprec. rates: 2.1%-4.0%. Has 14,500 employees. Chairman: George M. Smart. President & CEO: Anthony J. Alexander. COO: Richard R. Grigg. Inc.: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Tel.: 330-384-5100. Internet: www.firstenergycorp.com.

FirstEnergy is awaiting a ruling from the Public Utilities Commission of Ohio (PUCO) on the company's regulatory filing. Under FirstEnergy's proposal, rates of the company's three utility subsidiaries in Ohio would increase moderately in 2009 in order to reflect the rising cost of the power that FirstEnergy's nonregulated generating subsidiary is supplying to its utilities' customers. The proposal would also settle the utilities' pending distribution rate cases, for a total of $150 million (including a $50 million pass-through of higher costs) based on a 10.5% return on equity. (The utilities filed for a total of $332 million based on an 11.75% ROE.) The utilities would also benefit from a rate rider to recover reliability spending. This would amount to an estimated $110 million in 2009. The one negative aspect of the proposal is that Cleveland Electric would have to write off $485 million of unrecovered regulatory transition costs, thereby resulting in a charge of $1.01 a share. We would *exclude* this from our presentation as a nonrecurring item.

Earnings are likely to increase significantly in 2009. This assumes that the PUCO adopts the company's regulatory filing, since the alternative of going to market-based rates might well result in higher prices and more uncertainty for customers. We have cut our estimate by $0.20 a share, however, because in our August report we hadn't anticipated the sharp decline in pension assets that will cause pension expense to be significantly higher next year.

FirstEnergy is reviewing its capital budget. The company has adequate liquidity, but financing costs are rising. To this end, it appears as if FirstEnergy will postpone completion of an unfinished 707-megawatt gas-fired plant, since the weak economy is affecting the demand for power. In early 2008, FirstEnergy purchased the generating unit for $253.6 million, and it estimates that completing the facility would take another $208 million.

By utility standards, this stock offers a yield that is somewhat below average, but its 3- to 5-year total return potential is above average for a utility. We project solid earnings and dividend growth through the 2011-2013 period.

Paul E. Debbas, CFA *November 28, 2008*

(A) Dil. EPS. Excl. nonrec. losses: '02, 40¢; '03, 25¢; '04, 11¢; '05, 28¢; gains (losses) from disc. ops.: '03, (33¢); '04, 1¢; '05, 5¢; '06, (1¢). '06 EPS don't add due to chg. in shs., '07 due to rounding. Next egs. report due late Feb.
(B) Div'ds paid early Mar., June, Sept., & Dec. Five div'ds decl. in '04. ■ Div'd reinv. plan avail.
(C) Incl. intang.: In '07: $31.33/sh. (D) In mill.
(E) Rate base: Depr. orig. cost. Rate all'd on com. eq. in NJ in '05: 9.75%; in PA in '07: 10.1%; earn. on avg. com. eq., '07: 14.6%. Regul. Climate: OH, Above Avg.; PA, NJ, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	65

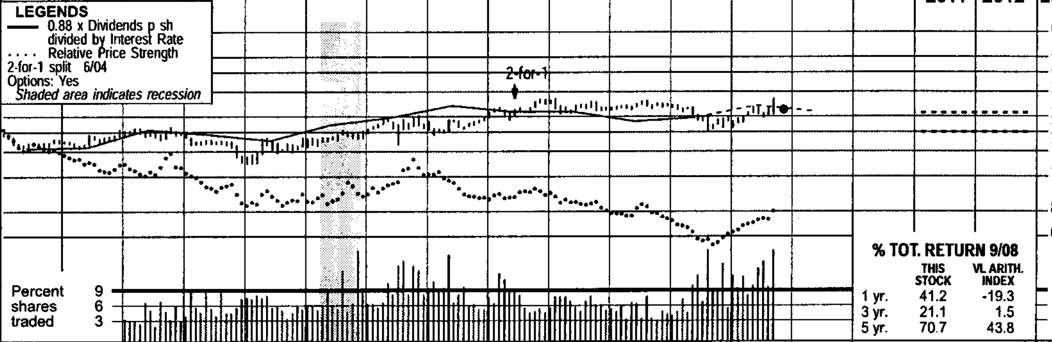
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 25.99 | P/E RATIO 21.8 (Trailing: 21.7 Median: 15.0) | RELATIVE P/E RATIO 1.96 | DIV'D YLD 4.8% | **VALUE LINE**

TIMELINESS 3 Lowered 7/18/08
SAFETY 2 Raised 2/15/02
TECHNICAL 3 Lowered 7/18/08
BETA .75 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	20.8	21.3	20.3	19.0	20.6	24.5	24.0	29.5	29.8	28.9	27.5	29.8
Low:	16.4	18.2	14.0	13.8	16.8	17.3	19.1	23.0	24.6	25.7	20.3	21.0

Target Price Range 2011 | 2012 | 2013



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(-5%)	4%
Low	20	(-25%)	-1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	2	0	0	2	0	1	1	0
Options	0	0	0	0	0	3	1	0	0
to Sell	0	0	0	0	0	3	2	0	2

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	87	94	113
to Sell	53	70	62
Hld's(000)	27714	30608	33450

% TOT. RETURN 9/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	41.2	-19.3
3 yr.	21.1	1.5
5 yr.	70.7	43.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
20.83	20.64	20.74	21.76	22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	30.40	*35.65*	*34.30*	Revenues per sh	*38.25*
2.51	2.23	2.52	2.73	2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	3.01	*3.15*	*3.55*	"Cash Flow" per sh	*4.00*
1.27	1.19	1.30	1.33	1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	1.11	*1.20*	*1.60*	Earnings per sh A	*1.75*
1.13	1.15	1.17	1.19	1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	*1.24*	*1.24*	Div'd Decl'd per sh B ■ †	*1.30*
4.03	4.06	3.50	3.27	3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	2.62	*4.10*	*3.45*	Cap'l Spending per sh	*2.75*
11.06	11.62	11.90	12.25	12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	15.29	*15.20*	*15.45*	Book Value per sh C	*16.75*
49.52	55.35	57.31	59.55	61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	83.43	*85.50*	*87.50*	Common Shs Outst'g D	*89.00*
15.3	15.5	12.5	13.5	13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	21.6	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.93	.92	.82	.90	.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	1.13	*Value Line*		Relative P/E Ratio	*.90*
5.8%	6.2%	7.2%	6.6%	6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*
						1485.2	1523.3	1719.0	1727.3	1653.7	1781.3	1924.1	2215.6	2460.9	2536.4	*3050*	*3000*	Revenues ($mill)	*3400*
						113.2	111.1	84.6	109.8	120.2	120.1	109.6	120.3	109.9	93.6	*105*	*140*	Net Profit ($mill)	*170*
						33.5%	33.9%	41.6%	34.6%	34.6%	34.9%	45.8%	36.4%	36.5%	35.4%	*39.0%*	*39.0%*	Income Tax Rate	*40.0%*
						14.2%	6.1%	9.8%	5.9%	4.8%	5.1%	7.6%	5.9%	8.4%	8.3%	*15.0%*	*14.0%*	AFUDC % to Net Profit	*5.0%*
						44.7%	47.2%	58.4%	56.9%	52.0%	48.6%	47.6%	45.2%	49.9%	47.6%	*48.5%*	*47.5%*	Long-Term Debt Ratio	*45.0%*
						43.1%	41.4%	39.9%	41.6%	46.5%	49.8%	51.0%	53.3%	48.6%	51.0%	*50.5%*	*51.0%*	Common Equity Ratio	*54.0%*
						1918.9	2049.5	2101.2	2235.8	2251.0	2186.9	2375.1	2283.9	2252.7	2501.8	*2585*	*2635*	Total Capital ($mill)	*2775*
						2093.4	2066.2	2091.3	2067.5	2079.3	2311.9	2422.3	2542.8	2647.5	2743.4	*2925*	*3055*	Net Plant ($mill)	*3225*
						7.4%	6.8%	5.9%	6.7%	7.3%	7.3%	6.0%	6.8%	6.4%	5.2%	*5.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
						10.7%	10.3%	9.7%	11.4%	11.1%	10.7%	8.8%	9.6%	9.7%	7.1%	*7.5%*	*10.0%*	Return on Shr. Equity	*11.0%*
						11.4%	11.0%	9.8%	11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	7.2%	*7.5%*	*10.5%*	Return on Com Equity E	*11.0%*
						1.8%	1.5%	1.7%	4.4%	4.3%	3.9%	1.1%	1.5%	.7%	.8%	*NMF*	*2.5%*	Retained to Com Eq	*3.5%*
						87%	88%	84%	63%	63%	64%	87%	85%	93%	89%	*104%*	*78%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 6/30/08
Total Debt $1428.9 mill. **Due in 5 Yrs** *$465.0* mill.
LT Debt *$1157.0* mill. **LT Interest** *$63.0* mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 2.7x)
Pension Assets-12/07 $907.3 mill. **Oblig.** $998.6 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 84,725,379 shs.
as of 7/30/08
MARKET CAP: $2.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+.3	+.3	--
Avg. Indust. Use (MWH)	6718	6623	6584
Avg. Indust. Revs. per KWH (¢)	15.21	17.38	17.68
Capacity at Yearend (Mw)	2184	2204	2223
Peak Load, Winter (Mw)	1641	1685	1635
Annual Load Factor (%)	74.1	72.5	74.7
% Change Customers (yr-end)	+1.7	+1.2	+1.3
Fixed Charge Cov. (%)	325	301	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	2.5%	4.0%	*4.5%*
"Cash Flow"	1.0%	-1.0%	*4.0%*
Earnings	-.5%	-3.0%	*5.0%*
Dividends	.5%	--	*1.0%*
Book Value	1.5%	2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	472.6	522.3	595.9	624.8	2215.6
2006	574.9	605.0	673.9	607.1	2460.9
2007	554.0	600.8	673.4	708.2	2536.4
2008	729.6	774.1	*775*	*771.3*	*3050*
2009	*750*	*750*	*750*	*750*	*3000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.30	.35	.46	.35	1.46
2006	.40	.33	.40	.20	1.33
2007	.17	.21	.24	.49	1.11
2008	.41	.06	*.40*	*.33*	*1.20*
2009	*.40*	*.40*	*.40*	*.40*	*1.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.31	.31	.31	.31	1.24
2005	.31	.31	.31	.31	1.24
2006	.31	.31	.31	.31	1.24
2007	.31	.31	.31	.31	1.24
2008	.31	.31	.31		

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 440,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Discontinued int'l power sub. in '01. Elec. rev. breakdown, '07: res'l, 34%; comm'l, 34%; large light & power, 31%; other, 1%. Generating sources, '07: oil, 61%; purchased, 39%. Fuel costs: 52% of revs. '07 reported depr. rate (utility): 3.8%. Has 3,500 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

Hawaiian Electric Industries' largest utility subsidiary has a rate case pending. Hawaiian Electric Company (HECO) filed for a tariff increase of $97.0 million (5.2%) based on a return on equity of 11.25%. The utility clearly needs rate relief: Its ROE was just 8.21% in the 12-month period that ended in mid-2008. HECO is asking for an interim rate hike of $73.1 million, followed by an increase of $23.9 million when a 110-megawatt peaking plant goes into service in mid-2009 at an estimated cost of $164 million. An interim rate order is due by mid-2009.

HEI's utilities are seeking to decouple electric revenues from electric sales. This is part of an agreement with the state government (which requires approval of the state commission) that includes high long-term requirements for renewable energy. Thus, conservation by customers would no longer hurt corporate profits. The plan would necessitate the building of a transmission line connecting Maui and Oahu, at a cost of $500 million-$1 billion.

The utilities' kilowatt-hour sales are flattening. Electric customers have stepped up their conservation efforts in the face of sharply higher rates (driven not only by base tariff hikes but by the rise in the cost of oil that fuels the company's plants). What's more, high air fares and the weak economy are hurting the tourism industry that is a key part of Hawaii's economy. We have cut our 2009 share-earnings estimate by $0.05 as a result.

A major move by American Savings Bank (ASB) caused HEI's earnings to fall into the red in the second quarter, but offers some benefits for HEI. ASB shrank its balance sheet by selling assets and unwinding liabilities. This forced HEI to take a $35.6 million aftertax charge that caused June-quarter results to decline sharply, but freed up some $75 million of capital that can be sent up to the parent company. Of this amount, $54.7 million has already been transferred.

This stock has held up much better than most utility issues since the market downturn last month. Accordingly, its yield is now about equal to the industry average, making this issue unattractive, in view of HEI's poor dividend growth potential.

Paul E. Debbas, CFA *November 7, 2008*

(A) Diluted EPS. Excl. gains (losses) from disc. ops.: '98, (16¢); '99, 6¢; '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due late Feb.
(B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '07: $4.41/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '07: HECO, 10.7% (interim); in '07: HELCO, 10.7%; in '07: MECO, 10.7%; earned on avg. com. eq., '07: 7.7%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	70

MDU RESOURCES NYSE-MDU

RECENT PRICE 17.60 | P/E RATIO 8.5 (Trailing: 8.3 Median: 14.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 2 Lowered 10/24/08

SAFETY 1 Raised 8/17/01

TECHNICAL 3 Lowered 9/5/08

BETA .95 (1.00 = Market)

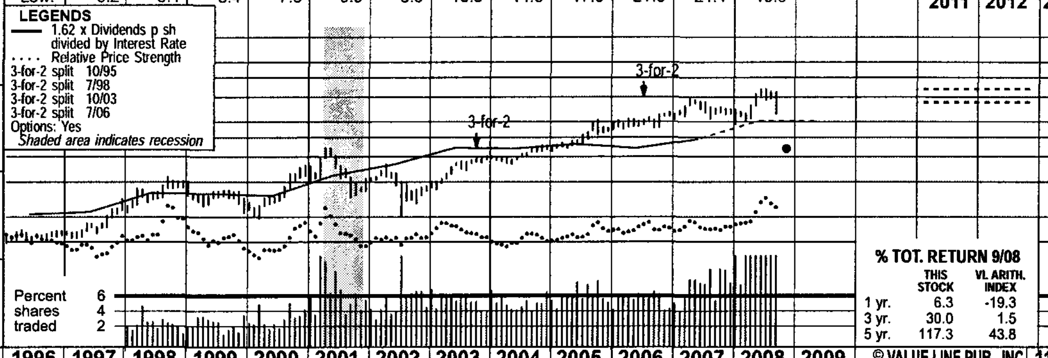
High:	9.9	12.8	12.1	14.7	17.9	14.9	16.2	18.5	24.8	27.0	31.8	35.3
Low:	6.2	8.4	8.4	7.8	9.9	8.0	10.9	14.6	17.0	21.8	24.4	15.9

Target Price Range 2011 | 2012 | 2013

2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+100%)	20%
Low	30	(+70%)	16%

LEGENDS
— 1.62 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 10/95
3-for-2 split 7/98
3-for-2 split 10/03
3-for-2 split 7/06
Options: Yes
Shaded area indicates recession



Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	3	0	0	0
to Sell	0	0	1	0	0	2	0	0	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	135	143	178
to Sell	128	132	134
Hld's(000)	89630	91770	91667

Percent shares traded 6 4 2

% TOT. RETURN 9/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	6.3	-19.3
3 yr.	30.0	1.5
5 yr.	117.3	43.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
3.67	4.57	4.68	4.83	5.36	6.40	7.51	9.97	12.81	14.16	12.03	13.83	15.33	19.21	22.49	23.22	27.40	29.80	Revenues per sh	33.75
.77	.87	.91	1.00	1.12	1.26	1.27	1.29	1.51	1.84	1.74	2.18	2.37	2.80	3.25	3.41	3.90	4.15	"Cash Flow" per sh	5.00
.36	.40	.41	.42	.47	.55	.64	.68	.80	.98	.82	1.08	1.20	1.53	1.75	1.76	2.10	2.15	Earnings per sh A	2.50
.29	.30	.31	.32	.33	.33	.35	.36	.38	.40	.42	.44	.47	.49	.52	.56	.60	.64	Div'd Decl'd per sh B ■ †	.76
.74	1.07	.85	.87	1.16	1.18	.81	1.29	.84	1.35	1.66	1.84	1.90	2.84	2.81	3.05	4.05	4.10	Cap'l Spending per sh	4.50
3.16	3.31	3.40	3.51	3.65	4.07	4.62	5.22	6.02	7.07	7.71	8.44	9.39	10.43	11.88	13.75	14.75	16.20	Book Value per sh C	21.25
96.11	96.11	96.11	96.11	96.11	94.98	119.33	128.34	146.31	157.00	166.60	170.04	177.34	179.86	181.02	182.95	185.00	187.00	Common Shs Outst'g D	193.00
13.5	15.1	13.7	13.7	13.9	13.4	16.6	15.1	13.2	13.8	14.4	13.0	13.6	13.0	13.7	15.7	Bold figures are		Avg Ann'l P/E Ratio	12.5
.82	.89	.90	.92	.87	.77	.86	.86	.86	.71	.79	.74	.72	.69	.74	.83	Value Line		Relative P/E Ratio	.85
5.9%	5.0%	5.6%	5.5%	5.1%	4.5%	3.3%	3.6%	3.6%	3.0%	3.6%	3.1%	2.9%	2.5%	2.2%	2.0%	estimates		Avg Ann'l Div'd Yield	2.4%

CAPITAL STRUCTURE as of 6/30/08
Total Debt $1642.2 mill. Due in 5 Yrs $511.6 mill.
LT Debt $1474.9 mill. LT Interest $84.8 mill.
(LT interest earned: 8.2x)
Leases, Uncapitalized Annual rentals $20.3 mill.
Pension Assets-12/07 $331.0 mill. Oblig. $359.9 mill.
Pfd Stock $15.0 mill. Pfd Div'd $.7 mill.
50,000 shs. 4.7% cum. ($100 par), call. at $102;
100,000 shs. 4.5% ($100 par), call. at $105.
Common Stock 183,216,763 shs.
as of 7/31/08

MARKET CAP: $3.2 billion (Mid Cap)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
896.6	1279.8	1873.7	2223.6	2004.1	2352.2	2719.3	3455.4	4070.7	4247.9	5070	5575	Revenues ($mill)	6500
74.0	84.1	111.0	149.6	131.8	182.9	212.4	275.1	317.9	322.8	390	400	Net Profit ($mill)	500
37.1%	37.0%	38.5%	38.6%	36.4%	35.0%	30.9%	34.6%	34.2%	37.1%	36.5%	36.5%	Income Tax Rate	36.5%
.4%	2.1%	4.7%	4.4%	5.8%	1.4%	2.9%	4.2%	2.6%	2.2%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
42.1%	45.1%	44.8%	41.0%	38.7%	39.3%	34.2%	36.9%	35.1%	31.2%	36.0%	35.0%	Long-Term Debt Ratio	30.0%
56.2%	53.6%	54.2%	58.1%	60.6%	60.1%	65.2%	62.6%	64.5%	68.4%	63.5%	64.5%	Common Equity Ratio	69.5%
980.7	1249.6	1625.6	1909.8	2119.5	2390.1	2554.5	2996.4	3335.5	3678.1	4290	4685	Total Capital ($mill)	5875
1084.7	1248.2	1601.0	1809.3	1924.9	2222.3	2572.7	3049.9	2993.4	3659.6	4475	4870	Net Plant ($mill)	6100
8.8%	8.2%	8.4%	9.2%	7.3%	8.7%	9.5%	10.2%	10.7%	9.8%	10.0%	9.5%	Return on Total Cap'l	9.5%
13.0%	12.3%	12.4%	13.3%	10.1%	12.6%	12.6%	14.5%	14.7%	12.8%	14.5%	13.0%	Return on Shr. Equity	12.0%
13.3%	12.4%	12.5%	13.4%	10.2%	12.7%	12.7%	14.6%	14.8%	12.8%	14.5%	13.0%	Return on Com Equity E	12.0%
5.9%	5.7%	6.5%	7.9%	5.0%	7.6%	7.9%	10.0%	10.4%	8.8%	10.5%	9.0%	Retained to Com Eq	8.5%
56%	55%	49%	41%	52%	40%	38%	32%	29%	31%	28%	30%	All Div'ds to Net Prof	29%

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+4.8	+2.9	+4.8
Avg. Indust. Use (MWH)	1219	1268	1358
Avg. Indust. Revs. per KWH (¢)	4.57	4.70	4.83
Capacity at Peak (Mw)	546	547	571
Peak Load, Summer (Mw)	470	485	526
Annual Load Factor (%)	58.0	56.0	NA
% Change Customers (avg.)	+.6	+.6	+.8
Fixed Charge Cov. (%)	663	651	690

BUSINESS: MDU Resources Group, Inc. is a diversified energy company. Montana-Dakota Utilities sells gas & electricity to 863,000 customers in ND, MT, SD, WY, MN, WA, ID, & OR. Elec. rev. breakdown, '07: res'l, 39%; comm'l, 42%; ind'l, 12%; other, 7%. Generating sources, '07: coal, 77%; other, 1%; purch., 22%. Also has operations in gas pipelines, oil & gas production, aggregates mining, construction materials production, utility line construction & maintenance. Acq'd Cascade Natural Gas 7/07; Intermountain Gas 10/08. '07 depr. rate: 5.1%. Has 12,600 employees. Chairman: Harry J. Pearce. President & CEO: Terry D. Hildestad. Inc.: DE. Address: 1200 West Century Ave., P.O. Box 5650, Bismarck, ND 58506-5650. Tel.: 701-530-1000. Internet: www.mdu.com.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	14.5%	10.5%	7.5%
"Cash Flow"	11.0%	13.0%	8.0%
Earnings	13.5%	14.0%	7.0%
Dividends	5.0%	5.5%	6.5%
Book Value	12.5%	11.5%	10.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	604.3	770.2	1066.8	1014.1	3455.4
2006	814.8	973.2	1190.6	1092.1	4070.7
2007	787.5	982.4	1245.3	1232.7	4247.9
2008	1122	1252	1275	1421	5070
2009	1350	1275	1425	1525	5575

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.19	.45	.48	.41	1.53
2006	.29	.39	.61	.45	1.75
2007	.23	.45	.57	.52	1.76
2008	.39	.63	.58	.50	2.10
2009	.35	.60	.65	.55	2.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.113	.113	.113	.12	.46
2005	.12	.12	.12	.127	.49
2006	.127	.127	.127	.135	.52
2007	.135	.135	.135	.145	.55
2008	.145	.145	.145	.155	

A strong first half of 2008 should enable MDU Resources' earnings to rise sharply for the full year . . . Led by much higher gas and oil prices along with higher production, earnings rose 50% in the first half. The Construction Services segment also fared well. Profits from the gas utility operations advanced largely due to the contribution from Cascade Natural Gas, which MDU acquired in July of 2007.

. . . despite the fact that near-term prospects in a couple of divisions have dimmed lately. Gas and oil prices have declined considerably since the first half of the year. That's largely why the stock, having fallen more than 30% since our August report, has underperformed the market since then. In addition, MDU has trimmed its expectation of production growth in 2008 (most of which is thanks to a large acquisition in January) from 12%-16% to 10%-14%. The Construction Materials division is feeling the effects of the slump in housing starts. Backlog is lower than a year ago and has become even more skewed towards public construction, which carries lower margins than private construction. And even in public construction, there are weak spots because some states' budgets are under pressure as tax revenues decline and costs rise. All of this explains why, even after a much better-than-expected tally in the June quarter, we raised our 2008 earnings estimate by just $0.10 a share, to $2.10. Since some operations are still faring well, we look for a modest earnings increase in 2009, but well below MDU's 7%-10% annual goal.

MDU completed a large utility acquisition. At the start of October, it paid $328 million (including the assumption of $80 million-$85 million of debt) for Intermountain Gas, which serves 302,000 customers in Idaho. The purchase should be slightly accretive to earnings next year.

The company's long-term prospects are bright. MDU's financial strength should help it ride out the effects of the current economic weakness. Also, in the past year, the gas and oil division has begun drilling in new (to MDU) areas of North Dakota and Utah, and the initial signs are promising. This timely stock offers worthwhile (by utility standards) total return potential to 2011-2013.

Paul E. Debbas, CFA *November 7, 2008*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '93, 6¢; '98, (34¢); '01, 4¢; '02, 10¢; '03, (5¢); '04, (3¢); gain (loss) on disc. ops.: '06, (1¢); '07, 60¢. '06 & '07 EPS don't add due to rounding. Next egs. report due early Feb. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang.: In '07: $3.10/sh. (D) In mill., adj. for splits. (E) Rate base: varies. Rates all'd on com. eq.: 11.4%-13.0%; earned on avg. com. eq., '07: 14.1%. Regul. Climate: ND, MT, Avg.; SD, Above Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	95
Earnings Predictability	80

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 37.39 | P/E RATIO 29.2 (Trailing: 29.2 Median: 16.0) | RELATIVE P/E RATIO 1.92 | DIV'D YLD 3.2% | VALUE LINE

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
High:	19.2	21.4	22.8	29.0	31.0	34.9	28.9	27.5	32.0	31.9	39.4	46.2
Low:	15.0	15.1	17.0	17.8	23.0	22.8	23.8	23.8	24.0	25.8	29.0	31.3

TIMELINESS **3** Raised 6/13/08

SAFETY **2** New 7/27/90

TECHNICAL **2** Raised 8/15/08

BETA .85 (1.00 = Market)

2011-13 PROJECTIONS

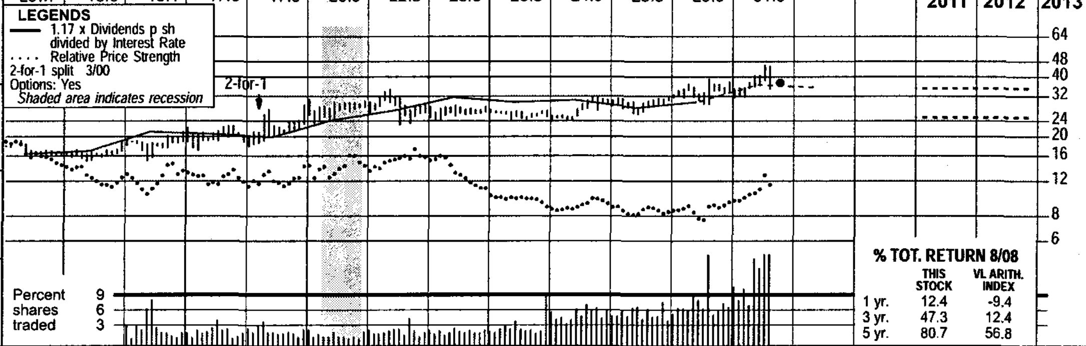
	Price	Gain	Ann'l Total Return
High	35	(-5%)	2%
Low	25	(-35%)	-5%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	3	3	3	1	0
to Sell	0	0	0	0	3	3	5	1	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	37	45	56
to Sell	47	35	40
Hld's(000)	13790	13984	14922



% TOT. RETURN 8/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	12.4	-9.4
3 yr.	47.3	12.4
5 yr.	80.7	56.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
9.37	11.86	12.86	14.70	16.13	16.80	18.14	19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	*35.95*	*37.95*	Revenues per sh	*40.50*
2.03	2.25	2.33	2.47	2.78	2.95	2.75	2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	*2.65*	*3.20*	"Cash Flow" per sh	*3.75*
1.09	1.12	1.17	1.19	1.24	1.29	1.29	1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	*1.25*	*1.55*	Earnings per sh A	*2.00*
.82	.84	.86	.88	.90	.93	.96	.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	*1.19*	*1.21*	Div'd Decl'd per sh B ■	*1.27*
1.01	1.38	1.36	1.66	2.85	1.79	1.23	1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	*7.65*	*4.85*	Cap'l Spending per sh	*5.00*
7.36	7.62	7.90	8.24	8.61	8.96	9.47	10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	*20.80*	*21.20*	Book Value per sh C	*23.00*
22.36	22.36	22.36	22.36	22.43	23.46	23.76	23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	*36.00*	*36.10*	Common Shs Outst'g D	*38.00*
15.5	15.6	13.8	14.2	14.0	12.8	14.4	13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.94	.92	.91	.95	.88	.74	.75	.79	.88	.84	.87	1.01	.91	.82	.93	1.00			Relative P/E Ratio	*1.00*
4.9%	4.8%	5.3%	5.2%	5.2%	5.6%	5.2%	4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%			Avg Ann'l Div'd Yield	*4.3%*

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
431.1	464.6	559.4	654.1	710.1	753.2	882.3	1046.4	1105.0	1238.9	*1295*	*1370*	Revenues ($mill)	*1535*
32.6	36.9	40.2	43.6	46.1	39.7	40.0	52.9	50.8	54.0	*41.0*	*55.0*	Net Profit ($mill)	*75.0*
33.5%	32.2%	30.3%	31.5%	30.3%	27.4%	29.8%	34.6%	34.8%	34.1%	*31.0%*	*31.0%*	Income Tax Rate	*31.0%*
.3%	.7%	.8%	3.1%	5.7%	5.0%	2.4%	1.7%	1.9%	4.2%	*12.0%*	*14.0%*	AFUDC % to Net Profit	*11.0%*
40.7%	38.7%	39.5%	43.5%	44.0%	43.2%	37.1%	35.0%	33.5%	38.9%	*39.0%*	*38.5%*	Long-Term Debt Ratio	*45.0%*
50.6%	53.9%	53.5%	53.5%	53.4%	54.3%	60.7%	62.9%	64.5%	59.4%	*59.5%*	*60.5%*	Common Equity Ratio	*54.0%*
445.0	455.6	484.4	522.2	587.2	614.6	706.5	738.2	763.0	882.1	*1255*	*1265*	Total Capital ($mill)	*1625*
500.2	503.0	515.9	543.0	587.9	633.3	682.1	697.1	718.6	854.0	*1075*	*1190*	Net Plant ($mill)	*1575*
9.0%	9.7%	9.6%	9.3%	9.0%	7.8%	6.8%	8.3%	7.7%	7.2%	*4.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
12.4%	13.2%	13.7%	14.8%	14.0%	11.4%	9.0%	11.0%	10.0%	10.0%	*5.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
13.5%	14.1%	14.8%	14.9%	14.5%	11.7%	9.1%	11.2%	10.2%	10.2%	*5.5%*	*7.5%*	Return on Com Equity E	*8.5%*
3.4%	4.5%	5.4%	5.8%	6.0%	3.2%	2.5%	4.2%	3.3%	3.5%	*Nil*	*1.5%*	Retained to Com Eq	*3.0%*
77%	70%	65%	63%	60%	73%	73%	63%	68%	66%	*98%*	*77%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 6/30/08
Total Debt $531.6 mill. **Due in 5 Yrs** $296.1 mill.
LT Debt $341.6 mill. **LT Interest** $21.0 mill.
(LT interest earned: 4.6x)

Leases, Uncapitalized Annual rentals $43.3 mill.
Pension Assets-12/07 $170.9 mill. **Oblig.** $185.2 mill.
Pfd Stock $15.5 mill. **Pfd Div'd** $.7 mill.
155,000 shs. $3.60-$6.75, cum., no par ($100 liquidating value).
Common Stock 30,172,396 shs.
as of 7/31/08
MARKET CAP: $1.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+3.2	+2.5	+3.3
Avg. Indust. Use (MWH)	29379	30169	31458
Avg. Indust. Revs. per KWH (¢)	4.96	5.04	5.20
Capacity at Peak (Mw)	714	711	NA
Peak Load, Winter (Mw)	665	690	705
Annual Load Factor (%)	66.5	66.2	NA
% Change Customers (yr-end)	+.2	+.5	+.2
Fixed Charge Cov. (%)	483	446	410

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	9.0%	8.0%	1.0%
"Cash Flow"	2.5%	.5%	1.5%
Earnings	3.5%	.5%	2.5%
Dividends	2.5%	2.0%	1.5%
Book Value	7.0%	7.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	232.1	256.4	272.7	285.2	1046.4
2006	257.8	279.9	280.6	286.7	1105.0
2007	301.1	305.9	302.2	329.7	1238.9
2008	300.2	323.6	*331.2*	*340*	*1295*
2009	*335*	*340*	*345*	*350*	*1370*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.37	.37	.61	.42	1.78
2006	.50	.37	.45	.37	1.69
2007	.34	.53	.44	.46	1.78
2008	.27	.11	*.45*	*.42*	*1.25*
2009	*.30*	*.35*	*.45*	*.45*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.275	.275	.275	.275	1.10
2005	.28	.28	.28	.28	1.12
2006	.288	.288	.288	.288	1.15
2007	.293	.293	.293	.293	1.17
2008	.298	.298	.298		

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to 129,000 customers in a mainly rural area in Minnesota (50% of retail elec. revs.), North Dakota (41%), and South Dakota (9%). Elec. rev. breakdown, '07: residential, 28%; commercial & farms, 35%; industrial, 21%; other, 16%. Generating sources: coal, 52%; other, 1%; purchased, 47%. Fuel costs: 11% of revs. Has operations in manufacturing, plastics, health services, food ingredients, & others (55% of '07 net inc.). '07 reported deprec. rate (utility): 2.8%. Has 4,300 employees. Chairman: John MacFarlane. Pres. & CEO: John D. Erickson. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, MN 56538-0496. Tel.: 218-739-8479. Internet: www.ottertail.com.

Otter Tail Corporation's stock has been on a wild ride lately. Due to investors' enthusiasm about the potential of the company's wind-tower manufacturing business, which ought to benefit from increased demand for wind-power equipment, the share price reached the mid-40s in early August. But it fell 20% in one day after Otter Tail reported very disappointing second-quarter earnings. The stock has made a partial recovery since then.

The wind-tower manufacturing business represents a small part of Otter Tail's overall enterprise. This unit is one of four companies in Otter Tail's Manufacturing division, which generated 29% of net income in 2007. (Management has not said how much manufacturing income came from the wind-tower unit.) So, this stock is hardly a pure play in wind power.

We have slashed our 2008 earnings estimate by $0.55 a share. A new wind-tower manufacturing facility is having start-up problems that might well last until early 2009. Most of the company's other nonutility businesses have experienced year-to-year bottom-line declines as well. On the utility side, Otter Tail Power was granted a final rate hike in Minnesota of $3.8 million (2.9%) that was lower than the interim tariff increase of $7.1 million (5.4%), so the utility had to refund some previously collected revenues. There will also be some dilution from the upcoming sale of at least five million common shares. Our revised estimate is at the bottom end of the company's guidance of $1.25-$1.50 a share. We have also cut our 2009 forecast.

More regulatory matters are upcoming. Otter Tail Power plans to file rate cases this fall in North Dakota and South Dakota. Rate orders are expected around mid-2009. Also, the utility is awaiting permission from the Minnesota commission to build a transmission line in the state, which would be necessary for the coal-fired plant it wants to build in South Dakota. A ruling probably won't come until early 2009.

We continue to think that this stock is overvalued. Most of Otter Tail's nonutility businesses are cyclical, and the utility operation generates nearly half of corporate profits, yet the relative price-earnings ratio is much higher than historical levels.

Paul E. Debbas, CFA *September 26, 2008*

(A) Diluted earnings. Excl. nonrecurring gains: '98, 7¢; '99, 34¢; gains from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢. '05 & '07 earnings don't add to full-year total due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '07: $5.55/sh. (D) In mill., adj. for split. (E) Rate allowed on com. eq. in MN in '08: 10.43%; earned on avg. com. eq., '07: 10.5%. Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	45
Earnings Predictability	80

PG&E CORP. NYSE-PCG

RECENT PRICE **37.83** | P/E RATIO **12.5** (Trailing: 13.8; Median: 15.0) | RELATIVE P/E RATIO **1.13** | DIV'D YLD **4.3%** | **VALUE LINE**

TIMELINESS **3**	Raised 7/11/08
SAFETY **2**	Raised 5/12/06
TECHNICAL **3**	Raised 8/15/08
BETA .85 (1.00 = Market)	

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	30.9	35.1	34.0	31.8	20.9	23.8	28.0	34.5	40.1	48.2	52.2	45.7
Low:	20.9	29.1	20.3	17.0	6.5	8.0	11.7	25.9	31.8	36.3	42.6	26.7

2011-13 PROJECTIONS

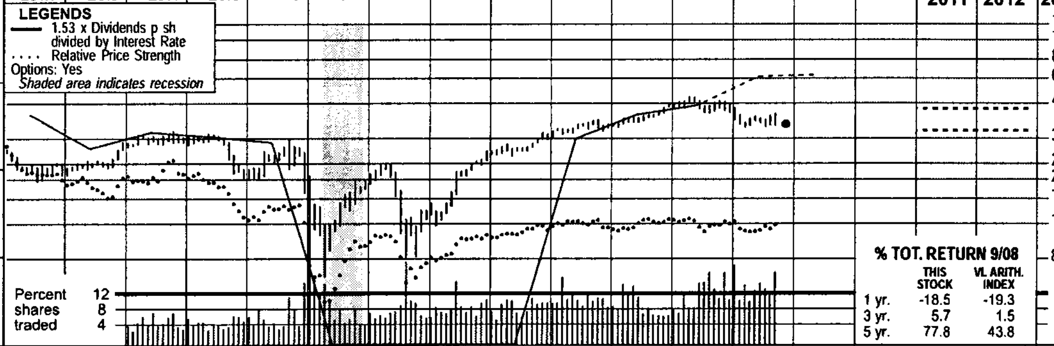
	Price	Gain	Ann'l Total Return
High	45	(+20%)	9%
Low	35	(-5%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	0	0	0	0	3
to Sell	0	12	0	0	0	0	0	0	3

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	199	171	189
to Sell	174	197	158
Hld's(000)	237710	241684	243516



% TOT. RETURN 9/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-18.5	-19.3
3 yr.	5.7	1.5
5 yr.	77.8	43.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
24.12	24.77	24.28	23.24	23.82	36.87	52.12	57.74	67.75	63.18	32.74	25.05	26.47	31.78	33.63	34.98	***38.50***	***40.25***	Revenues per sh	***46.50***
5.42	5.42	5.99	6.31	5.24	5.98	6.08	7.15	.80	5.66	1.14	4.80	5.71	7.12	7.20	7.32	***7.90***	***8.45***	"Cash Flow" per sh	***9.75***
2.58	2.33	2.76	2.95	2.16	1.57	1.88	2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.77	2.78	***2.95***	***3.20***	Earnings per sh A	***3.50***
1.76	1.88	1.96	1.96	1.77	1.20	1.20	1.20	1.20	--	--	--	--	.90	1.32	1.41	***1.56***	***1.68***	Div'd Decl'd per sh B■†	***2.04***
5.41	4.13	2.54	2.25	3.05	4.36	4.23	4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.44	7.32	***9.95***	***9.80***	Cap'l Spending per sh	***9.55***
19.41	19.77	20.07	20.77	20.73	21.30	21.08	19.10	8.19	11.89	9.47	10.12	20.62	19.60	20.95	22.60	***24.05***	***25.50***	Book Value per sh C	***29.95***
426.85	427.22	430.24	414.03	403.50	417.67	382.60	360.59	387.19	363.38	381.67	416.52	418.62	368.27	372.80	378.39	***382.00***	***387.00***	Common Shs Outst'g D	***398.00***
12.3	14.8	9.5	9.4	10.9	15.5	16.8	13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	***11.5***
.75	.87	.62	.63	.68	.89	.87	.75	--	.25	--	.54	.73	.82	.80	.88	*Value Line*		Relative P/E Ratio	***.75***
5.6%	5.5%	7.5%	7.1%	7.5%	4.9%	3.8%	4.1%	4.8%	--	--	--	--	2.5%	3.2%	3.0%	*estimates*		Avg Ann'l Div'd Yield	***5.1%***

CAPITAL STRUCTURE as of 6/30/08
Total Debt $8839 mill. **Due in 5 yrs** $2750 mill.
LT Debt $7721 mill. **LT Interest** $650.0 mill.
(LT interest earned: 3.2x)
Pension Assets-12/07 $9.5 bill. **Oblig.** $9.1 bill.
Pfd Stock $252.0 mill. **Pfd Div'd** $16.0 mill.
5,973,456 shs. 4.36% to 7.04%, cum. and $25 par, redeem. from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cum. nonredeem. and $25 par; 5,500,000 shs. 6.30% and 6.57%, cum. $25 par, mandat. redempt.

Common Stock 381,076,783 shs.
MARKET CAP: $14.4 billion (Large Cap)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
19942	20820	26232	22959	12495	10435	11080	11703	12539	13237	***14700***	***15570***	Revenues ($mill)	***18500***
746.0	825.0	d3324	1099.0	d874.0	791.0	901.0	904.0	991.0	1006.0	***1125***	***1235***	Net Profit ($mill)	***1400***
43.3%	1.6%	--	35.6%	--	36.7%	35.0%	37.6%	35.9%	34.9%	***35.0%***	***35.0%***	Income Tax Rate	***35.0%***
--	--	--	1.6%	--	3.7%	3.6%	5.6%	6.8%	9.5%	***8.0%***	***5.0%***	AFUDC % to Net Profit	***5.0%***
45.6%	46.5%	62.1%	58.9%	51.5%	42.4%	45.1%	48.3%	45.4%	48.1%	***49.0%***	***51.0%***	Long-Term Debt Ratio	***50.5%***
49.6%	48.0%	30.4%	34.9%	42.8%	53.9%	53.2%	50.0%	52.9%	50.4%	***49.5%***	***48.0%***	Common Equity Ratio	***49.0%***
16268	14339	10428	12399	8438.0	7815.0	16242	14446	14760	16976	***18540***	***20625***	Total Capital ($mill)	***24365***
17818	16776	16591	19167	16928	18107	18989	19955	21785	23656	***25555***	***27305***	Net Plant ($mill)	***31365***
6.5%	7.4%	NMF	13.3%	NMF	16.3%	7.6%	8.1%	8.4%	8.0%	***8.5%***	***8.0%***	Return on Total Cap'l	***8.0%***
8.4%	10.8%	NMF	21.5%	NMF	17.6%	10.1%	12.1%	12.3%	11.4%	***12.0%***	***12.0%***	Return on Shr. Equity	***11.5%***
8.9%	11.6%	NMF	22.9%	NMF	18.5%	10.3%	12.3%	12.5%	11.7%	***12.0%***	***12.5%***	Return on Com Equity E	***11.5%***
3.4%	5.2%	NMF	22.9%	NMF	18.5%	10.3%	7.7%	6.6%	5.9%	***6.0%***	***6.0%***	Retained to Com Eq	***5.0%***
63%	56%	NMF	10%	--	2%	1%	39%	48%	50%	***53%***	***53%***	All Div'ds to Net Prof	***59%***

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	-1.6	+5.8	+2.2
Avg. Indust. Use (MWH)	12341	12536	12253
Avg. Indust. Revs. per KWH (¢)	8.15	8.60	8.34
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	--	+2.7	+2.0
Fixed Charge Cov. (%)	309	263	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	2.0%	-9.5%	*5.5%*
"Cash Flow"	2.0%	23.5%	*5.0%*
Earnings	1.5%	--	*5.0%*
Dividends	-3.0%	--	*9.0%*
Book Value	--	16.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	2669	2498	2804	3732	11703
2006	3148	3017	3168	3206	12539
2007	3356	3187	3279	3415	13237
2008	3733	3578	***3600***	***3789***	***14700***
2009	***3950***	***3780***	***3850***	***3990***	***15570***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.54	.70	.62	.49	2.35
2006	.60	.65	1.09	.43	2.77
2007	.71	.74	.77	.56	2.78
2008	.62	.80	***.95***	***.58***	***2.95***
2009	***.70***	***.85***	***1.00***	***.65***	***3.20***

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	--	--	--	--	--
2005	--	.30	.30	.30	.90
2006	.33	.33	.33	.33	1.32
2007	.33	.36	.36	.36	1.41
2008	.36	.39	.39	.39	

BUSINESS: PG&E Corporation is a holding co. for Pacific Gas and Electric Company and nonutil. subsids. Supplies electricity and gas in 48 Calif. counties. Owns generation elsewhere in the U.S. Elect. (and gas) rev. breakdown: resid., 36% (75%); commer., 39% (25%); indust., 18% (under 1%); other, 7%. Petroleum refining industry is the largest elect. and gas customer. '07 megawatt capacity: hydro, 62%; fossil fuels, 2%; nuclear, 36%. Fuel costs: 41% of utility revenues; labor costs (system): 15%. '07 deprec. rate: 3.3%. Est'd plant age: 9 years. Has 20,050 employees. Chairman, President & Chief Executive Officer: Peter A. Darbee. Inc.: Calif. Address: 77 Beale Street, San Francisco, Calif. 94106. Tel.: 1-800-367-7731. Internet: www.pgecorp.com.

PG&E keeps adding generation to meet customer needs. Construction is near completion on the 530-megawatt (mw) gas-fired Gateway plant, which is scheduled to go on line in early 2009. The unit will be followed a year later by the 657-mw Colusa gas-fired station. Meanwhile, the company awaits approval to repower the 163-mw Humboldt gas- and oil-powered facility, to extend its useful life. Also on the agenda are increases in renewable energy sources. Under contract are some 1,200 mw of wind-driven power, which will be available in the summer of 2010. Too, last August, PG&E agreed to buy 800 mw of solar energy and may increase the amount to 2,000 mw. The wind and solar purchases, plus lesser additions of biomass and geothermal energy, will be sufficient to meet the state's renewable energy requirements. The new power should not only satisfy rising demand for a while, but should permit retirement of older and more costly plants.

The program entails periodic trips to the capital markets. Construction costs for the next three years are projected at $3.8 billion annually. Since cash flow from operations will fall short of covering these outlays, management plans to issue about $1.4 billion of long-term debt each year through 2011 to bridge the gap. And depending on market conditions, it will sell from $1.1 billion to $1.7 billion of common stock over the same period. These offerings would reduce the common equity ratio only modestly.

Earnings should continue to rise this year. The big pluses are a full year of 2007's $243 million rate increase and the $125 million attrition rate boost in 2008. Other positives include profits from new plants in operation and a reduction in headcount resulting from the installation of "smart" meters. Despite higher interest expense, we are retaining our 2008 earnings estimate of $2.95 a share. Further gains are likely for the next few years.

Income-oriented investors might take a look here. The yield is near the industry norm, but dividend growth prospects to 2011-2013 exceed the group average. What's more, since PG&E's exit from bankruptcy in April, 2004, finances have been restored to a satisfactory level.

Arthur H. Medalie *November 7, 2008*

(A) EPS diluted. Excl. nonrecurring gains (losses): '94, (55¢); '95, 4¢; '96, (41¢); '97, 18¢; '99, ($2.44); '04, $6.95. Incl. '00 nonrecurring loss: $11.83. Next earnings report due early Nov. (B) Dividends historically paid in mid-Jan., Apr., July, Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intang. In '07: $11.80/sh. (D) In millions. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '07: 11.35%. Earned on avg. com. eq. in '07: 12.3%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	5

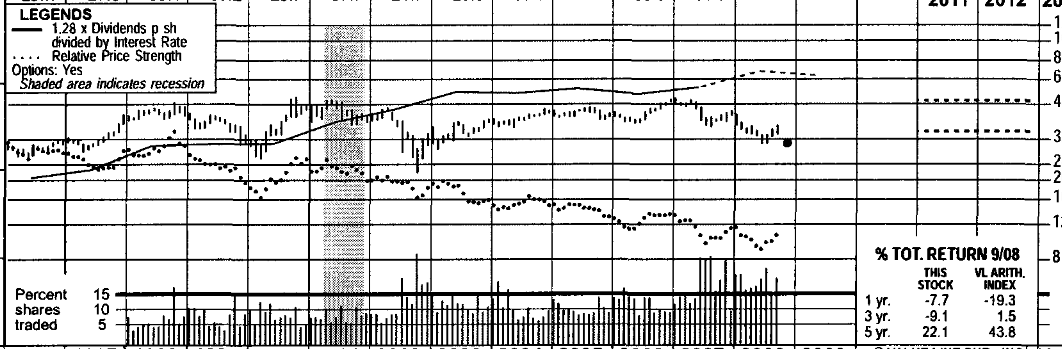
PINNACLE WEST NYSE-PNW

RECENT PRICE	30.68	P/E RATIO	10.1 (Trailing: 9.3, Median: 14.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	6.8%	VALUE LINE

TIMELINESS **3** Raised 9/26/08
SAFETY **2** Lowered 8/8/08
TECHNICAL **3** Raised 8/22/08
BETA .75 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	42.8	49.3	43.4	52.7	50.7	46.7	40.5	45.8	46.7	51.0	51.7	42.9
Low:	27.6	39.4	30.2	25.7	37.7	21.7	28.3	36.3	39.8	38.3	36.8	26.3

Target Price Range 2011 | 2012 | 2013



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+65%)	17%
Low	35	(+15%)	9%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	151	133	138
to Sell	125	136	128
Hld's(000)	82999	84951	80304

% TOT. RETURN 9/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-7.7	-19.3
3 yr.	-9.1	1.5
5 yr.	22.1	43.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
19.39	19.66	19.28	19.08	20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	*37.30*	*37.75*	Revenues per sh	44.55
4.70	5.25	5.09	5.16	5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	6.76	6.69	*6.90*	*7.00*	"Cash Flow" per sh	9.75
1.73	1.95	1.99	2.22	2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	*2.80*	*2.90*	Earnings per sh A	3.10
--	.20	.83	.93	1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	*2.10*	*2.10*	Div'd Decl'd per sh B■†	2.22
2.57	2.69	2.92	3.38	2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.38	9.14	*8.95*	*8.95*	Cap'l Spending per sh	9.40
17.00	18.87	20.32	21.49	22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.47	35.15	*35.90*	*36.60*	Book Value per sh C	39.10
87.16	87.42	87.43	87.52	87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	*100.70*	*106.00*	Common Shs Outst'g D	106.60
10.8	11.5	9.6	10.8	11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	*Bold figures are*		Avg Ann'l P/E Ratio	13.5
.66	.68	.63	.72	.74	.68	.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	*Value Line*		Relative P/E Ratio	.90
--	.9%	4.3%	3.9%	3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	5.3%

CAPITAL STRUCTURE as of 6/30/08
Total Debt $3477.5 mill. Due in 5 Yrs $1298.6 mill.
LT Debt $3086.2 mill. LT Interest $181.3 mill.
(LT interest earned: 3.2x)

Pension Assets-12/07 $1.32 bill. Oblig. $1.72 bill.

Pfd Stock None

Common Stock 100,733,570 shs. as of 8/4/08
MARKET CAP: $3.1 billion (Mid Cap)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
2130.6	2423.4	3690.2	4551.4	2637.3	2817.9	2899.7	2988.0	3401.8	3523.6	*3750*	*4000*	Revenues ($mill)	4750
252.6	270.8	283.6	312.2	215.2	230.6	235.2	223.2	317.1	298.8	*280*	*295*	Net Profit ($mill)	330
39.5%	38.3%	44.1%	40.6%	39.1%	31.4%	35.4%	36.2%	33.0%	33.6%	*34.0%*	*34.0%*	Income Tax Rate	34.0%
7.4%	4.3%	7.6%	15.3%	20.5%	6.2%	6.9%	10.4%	6.6%	14.8%	*4.0%*	*4.0%*	AFUDC % to Net Profit	4.0%
47.6%	50.0%	45.1%	51.7%	51.8%	50.6%	46.7%	43.2%	48.4%	47.0%	*46.5%*	*47.0%*	Long-Term Debt Ratio	49.0%
50.2%	50.0%	54.9%	48.3%	48.2%	49.4%	53.3%	56.8%	51.6%	53.0%	*53.5%*	*53.0%*	Common Equity Ratio	51.0%
4307.6	4411.8	4337.8	5172.4	5567.9	5727.5	5535.2	6033.4	6678.8	6658.7	*6735*	*7300*	Total Capital ($mill)	8170
4730.6	4778.5	5133.2	5907.3	6479.4	7480.1	7535.5	7577.1	7881.9	8436.4	*8925*	*9425*	Net Plant ($mill)	10745
7.6%	7.9%	8.1%	7.6%	5.4%	5.5%	5.6%	5.0%	6.2%	5.9%	*6.0%*	*5.5%*	Return on Total Cap'l	5.5%
11.2%	12.3%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	*8.0%*	*7.5%*	Return on Shr. Equity	8.0%
11.2%	12.2%	11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	*8.0%*	*7.5%*	Return on Com Equity E	8.0%
6.4%	7.1%	6.8%	7.3%	2.9%	2.6%	2.3%	1.0%	3.4%	2.5%	*2.0%*	*2.0%*	Retained to Com Eq	2.5%
45%	42%	43%	41%	64%	68%	71%	85%	63%	70%	*75%*	*72%*	All Div'ds to Net Prof	71%

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+4.4	+5.6	+4.3
Avg. Indust. Use (MWH)	670	730	665
Avg. Indust. Revs. per KWH (¢)	6.28	6.87	7.30
Capacity at Peak (Mw)	7412	7652	6783
Peak Load, Summer (Mw)	7000	7652	7545
Annual Load Factor (%)	50.0	48.0	51.4
% Change Customers (yr-end)	+4.3	+4.4	+3.3
Fixed Charge Cov. (%)	278	324	291

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	4.5%	-4.5%	5.0%
"Cash Flow"	.5%	-4.0%	7.5%
Earnings	1.0%	-2.5%	2.0%
Dividends	7.0%	5.5%	1.0%
Book Value	4.5%	3.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	585.0	755.8	955.6	691.6	2988.0
2006	670.2	925.0	1076.5	730.1	3401.8
2007	695.1	863.4	1205.9	759.2	3523.6
2008	736.7	926.2	*1260*	*827.1*	*3750*
2009	*800*	*990*	*1320*	*890*	*4000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.26	.88	.86	.24	2.24
2006	.12	1.11	1.84	.10	3.17
2007	.16	.78	1.99	.03	2.96
2008	d.04	1.33	*1.40*	*.11*	*2.80*
2009	*.20*	*.85*	*1.70*	*.15*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.45	.45	.45	.475	1.83
2005	.475	.475	.475	.50	1.93
2006	.50	.50	.50	.525	2.03
2007	.525	.525	.525	.525	2.10
2008	.525	.525	.525		

BUSINESS: Pinnacle West Capital Corporation (parent of Arizona Public Service) supplies electricity to approx. 1,780,000 people in 11 of 15 Arizona counties. Electric revenue sources: residential, 51%; commercial, industrial, and other, 49%. Power costs: 39% of electric revenues; labor costs: 13% of total revenues. The mining industry is the largest industrial customer. Energy sources: coal, 37%; nuclear, 22%; gas & other, 18%; purchased power, 23%. Has 7,600 employees. Reported '07 depreciation rate: 3.1%. Est'd plant age: 10 years. Chairman & Chief Executive Officer: William J. Post. Pres.: Jack E. Davis. Inc.: Arizona. Address: 400 E. Van Buren St., Suite 700, P.O. Box 52132, Phoenix, AZ 85072-2132. Tel.: 602-379-2568. Internet: www.pinnaclewest.com.

Pinnacle West has filed for $278.2 million in higher rates. The request reflects a test year ended December 31, 2007. It is based on an 11.50% return on equity, up from the present 10.25%. About 95% of the application is for nonfuel-related items. These components include new connections to existing customers, updating the cost of capital, and $79.3 million for an attrition adjustment to offset earnings erosion through 2010. PNW also seeks an interim surcharge of $115 million, which would be subject to refund. The petition asks that new rates be effective no later than October 1, 2009.

Despite a reduction in demand, the company still needs new generation. Due to a weak economy, energy sales growth has slowed from 3.5% in 2007 to about 2.0%, and it will probably remain near that figure for some time to come. Even the lesser increase requires new energy sources. To cover its obligations, Pinnacle has begun building a 100-mile, 500-kilovolt line in the Phoenix area that will increase capacity by 917 megawatts. And it has authority to construct another 122-mile line from the Palo Verde nuclear station hub to Yuma, Arizona. On the generation side, PNW recently bought a two-unit, 96-megawatt gas-fired unit. And pending approval of federal tax credits, it will buy 100% of a 280-mw solar powered facility that would be built by an outsider. These additions should meet customer requirements for the next several years.

Earnings are headed lower in 2008. Plant overhauls in the first quarter limited off-system sales and generated a deficit in that period. Too, the SunCor subsidiary may post no profits this year because of a soft real estate market. Though the June interim benefited from a one-time, $0.30-a-share tax ruling, we estimate 2008 earnings will decline 5%, to $2.80 a share. Higher rates suggest modest improvement next year.

The yield is above the industry average. But no boost in the payout is likely until the rate case is decided. A reasonable award should then result in a dividend hike. But future increases may be more modest than those of the past. On balance, we rate Pinnacle an average utility investment.

Arthur H. Medalie *November 7, 2008*

(A) Diluted egs. Excl. nonrecurring gains (losses): '93, 22¢; '94, 31¢; '95, net 6¢; '99, ($1.20); '02, (77¢); excl. gains (losses) from discontinued ops.: '92, 7¢; '99, ($1.97); '00, 22¢; '05, (36¢); '06, 10¢. Next earnings report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Divd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def. chgs. In '07: $7.36/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in '05: 10.25%; earned on avg. com. eq., '07: 8.6%. Reg. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	15
Earnings Predictability	60

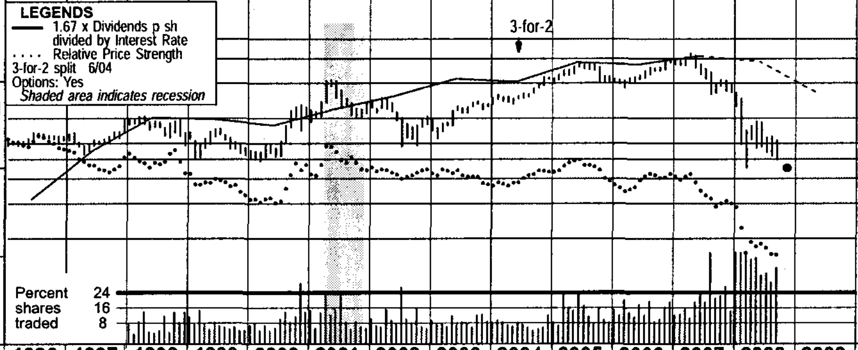
PNM RESOURCES NYSE-PNM

RECENT PRICE	9.03	P/E RATIO	8.4 (Trailing: NMF; Median: 14.0)	RELATIVE P/E RATIO	0.76	DIV'D YLD	5.5%	VALUE LINE

TIMELINESS 4 Raised 11/7/08
SAFETY 3 Lowered 5/9/08
TECHNICAL 3 Lowered 11/7/08
BETA .90 (1.00 = Market)

High:	15.8	16.5	14.3	18.9	25.2	20.5	19.6	26.1	30.5	32.1	34.3	21.7
Low:	10.5	11.6	9.9	9.8	15.3	11.5	12.6	18.7	23.8	22.5	21.0	7.6

Target Price Range
2011 | 2012 | 2013



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	11	(+20%)	10%
Low	7	(-20%)	Nil

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	2	0	0	1	0	0	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	91	107	103
to Sell	77	89	71
Hld's(000)	73435	66120	77467

% TOT. RETURN 9/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-53.8	-19.3
3 yr.	-60.0	1.5
5 yr.	-34.9	43.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
13.60	13.95	14.44	12.90	14.10	18.12	17.43	18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	*21.65*	*22.10*	Revenues per sh	*24.75*
2.10	2.34	2.55	2.38	2.61	2.58	3.04	2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	*1.75*	*2.40*	"Cash Flow" per sh	*3.25*
.50	.81	1.11	.91	1.15	1.25	1.50	1.29	1.55	2.61	1.07	1.15	1.43	1.59	1.72	.76	*.10*	*.60*	Earnings per sh A	*.95*
--	--	--	--	.24	.42	.51	.53	.53	.53	.57	.61	.63	.79	.86	.91	*.71*	*.50*	Div'd Decl'd per sh B ■†	*.50*
1.52	1.61	1.90	1.70	1.42	2.05	2.06	1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	*3.65*	*3.55*	Cap'l Spending per sh	*3.85*
10.00	8.86	10.08	11.22	12.04	12.84	13.75	14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	*19.75*	*19.85*	Book Value per sh C	*20.95*
62.66	62.66	62.66	62.66	62.66	62.66	62.66	61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	*91.00*	*91.00*	Common Shs Outst'g D	*91.00*
16.5	9.5	7.5	10.6	11.0	10.0	9.8	9.5	8.5	7.3	15.1	14.7	15.0	17.1	15.6	35.6	*Bold figures are*		Avg Ann'l P/E Ratio	*9.5*
1.00	.56	.49	.71	.69	.58	.51	.54	.55	.37	.82	.84	.79	.91	.84	1.88	*Value Line*		Relative P/E Ratio	*.65*
--	--	--	--	1.9%	3.3%	3.5%	4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*5.3%*
						1092.4	1157.5	1611.3	2352.1	1169.0	1455.7	1604.8	2076.8	2471.7	1914.0	*1970*	*2010*	Revenues ($mill)	*2250*
						105.2	79.9	92.7	156.3	64.3	68.9	88.3	106.6	122.1	59.9	*9.0*	*55.0*	Net Profit ($mill)	*85.0*
						34.9%	34.6%	44.5%	34.2%	24.5%	29.0%	28.2%	31.1%	24.7%	5.1%	*5.0%*	*25.0%*	Income Tax Rate	*25.0%*
						--	--	--	--	--	1.7%	3.4%	--	3.8%	.7%	*4.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
						53.2%	52.0%	50.4%	48.2%	49.8%	47.5%	47.1%	57.4%	50.9%	42.0%	*46.5%*	*48.0%*	Long-Term Debt Ratio	*49.5%*
						45.4%	47.3%	48.9%	51.1%	49.5%	51.9%	52.4%	42.3%	48.8%	57.6%	*53.0%*	*51.5%*	Common Equity Ratio	*50.0%*
						1896.4	1901.2	1891.3	1978.7	1966.9	2077.3	2098.9	3044.4	3470.7	2935.8	*3390*	*3500*	Total Capital ($mill)	*3800*
						1593.8	1582.4	1617.3	1781.0	1867.3	2194.4	2324.6	2984.1	3761.9	2935.4	*3115*	*3275*	Net Plant ($mill)	*3740*
						6.9%	5.9%	6.6%	9.5%	4.7%	4.7%	5.3%	4.7%	4.9%	3.4%	*2.0%*	*3.0%*	Return on Total Cap'l	*4.0%*
						11.8%	8.8%	9.9%	15.3%	6.5%	6.3%	7.9%	8.2%	7.2%	3.5%	*.5%*	*3.0%*	Return on Shr. Equity	*4.5%*
						12.1%	8.8%	10.0%	15.4%	6.5%	6.3%	8.0%	8.2%	7.2%	3.5%	*.5%*	*3.0%*	Return on Com Equity E	*4.5%*
						8.4%	5.2%	6.5%	12.3%	3.1%	3.0%	4.5%	4.3%	3.7%	NMF	*NMF*	*.5%*	Retained to Com Eq	*2.0%*
						31%	42%	35%	20%	53%	53%	44%	48%	49%	117%	*NMF*	*83%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 6/30/08
Total Debt $2413.9 mill. **Due in 5 Yrs** $1412.0 mill.
LT Debt $1517.0 mill. **LT Interest** $87.8 mill.
(LT interest not earned.)
Pension Assets-12/07 $501.7 mill. **Oblig.** $498.9 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.6 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 86,310,701 shs.
MARKET CAP: $775 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+2.9	+3.5	+1.6
Avg. Indust. Use (MWH)	4544	4756	4602
Avg. Indust. Revs. per KWH (¢)	4.79	4.71	5.20
Capacity at Peak (Mw)	1744	1934	2205
Peak Load, Summer (Mw)	1779	1855	1933
Annual Load Factor (%)	64.8	65.0	64.2
% Change Customers (yr-end)	+2.9	+2.7	+1.3
Fixed Charge Cov. (%)	165	166	122

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	7.0%	--	-2.5%
"Cash Flow"	2.5%	-1.0%	1.0%
Earnings	2.0%	-5.0%	-6.0%
Dividends	14.5%	9.5%	-9.0%
Book Value	5.5%	5.0%	Nil

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	427.9	405.3	597.1	646.5	2076.8
2006	655.8	546.7	650.2	619.0	2471.7
2007	437.0	505.6	569.9	401.5	1914.0
2008	364.5	580.3	*590*	*435.2*	*1970*
2009	*385*	*560*	*610*	*455*	*2010*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.50	.22	.46	.41	1.59
2006	.38	.23	.62	.49	1.72
2007	.19	.28	.15	.14	.76
2008	d.93	d.05	*.60*	*.48*	*.10*
2009	*.05*	*.05*	*.35*	*.15*	*.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.153	.16	.16	.16	.63
2005	.185	.185	.20	.20	.77
2006	.20	.20	.22	.22	.84
2007	.22	.23	.23	.23	.91
2008	.23	.23	.125		

BUSINESS: PNM Resources, parent of Public Service Company of New Mexico, sells electricity (more than 99% of revenues), other less than (1%) in north-central New Mexico (popul.: 1,300,000). Acquired TNP Enterprises 6/05. Largest customer: City of Albuquerque. Elect. rev. breakdown: resid., 25%; commer., 28%; indust, 8%; other, 39%. Area's military establishments are major customers. Fuels: coal, 65%; nuclear, 27%; gas/oil, 8%. Fuel costs: 59% of revs.; labor costs: 16%. '07 reported deprec. rate: 2.4%. Est'd plant age: 11 years. Has 3,124 employees. Chairman & Chief Executive Officer: Jeffry E. Sterba. President: Patricia K. Collawn. Inc.: New Mexico. Address: Alvarado Square, Albuquerque, New Mexico 87158. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources has a contract to sell its natural gas operations. Continental Energy has agreed to buy these assets for $620 million in cash. The deal will provide $463 million in aftertax proceeds and $100 million in profits, all of which the company will be allowed to keep. The pact requires approval of various state and federal regulatory bodies. Closing is expected by year-end. In a related matter, the parties have agreed to terminate PNM's pending purchase of Continental's Cap Rock Texas electric transmission and distribution facility. In exchange, Continental will pay PNM $15 million.

Earnings will probably fall far below 2007's dismal performance. PNM's unregulated Texas assets suffered damages in the range of $30 million to $35 million from last fall's Hurricane Ike, and these losses are not recoverable through rates. Too, planned outages at the San Juan coal-fired station have forced the company to buy power in a high-priced wholesale market. Despite last April's $34.4 million rate increase and improved operations at the Palo Verde nuclear station, we estimate 2008 profits will plunge to an all-time low of $0.10 a share and may improve only marginally next year. As a result . . .

The company has applied for much-needed rate relief. The $123.3 million request includes continued use of a fuel and purchased power cost adjustment clause, with 75% of off-system sales margins going to customers. In addition, costs associated with environmental improvements at the San Juan plants would be fully recovered. The filing also seeks recoupment of costs related to including 357 megawatts of power in PNM's retail generation rate base. This was previously approved by the commission staff and other interested parties. Finally, the petition asks for an 11.75% allowed return on equity, up from the current 10.10%. Whatever amounts are granted will take effect in August, 2009.

We'd avoid a commitment to this untimely stock, at this time. The recently reduced dividend won't be earned this year, and it may be barely covered in 2009. What's more, PNM's long-term debt is rated below investment grade by major rating organizations.

Arthur H. Medalie *November 7, 2008*

(A) EPS diluted. Next earnings report due mid-Nov. Excl. nonrecur. gains (losses): '92, ($2.28); '93, ($1.90); '94, 7¢; '95, net 23¢; '97, 3¢; '98, net (16¢); '99, 5¢; '00, 14¢; '01, (10¢); '03, 45¢; '05, (56¢); '07, 14¢. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '07: $13.72/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. Elect. ROE allowed in '08: 10.1%; earned on avg. com. eq., '07: 3.5%. Regulatory Climate: Avg.

Company's Financial Strength	B
Stock's Price Stability	60
Price Growth Persistence	60
Earnings Predictability	20

PPL CORPORATION NYSE-PPL

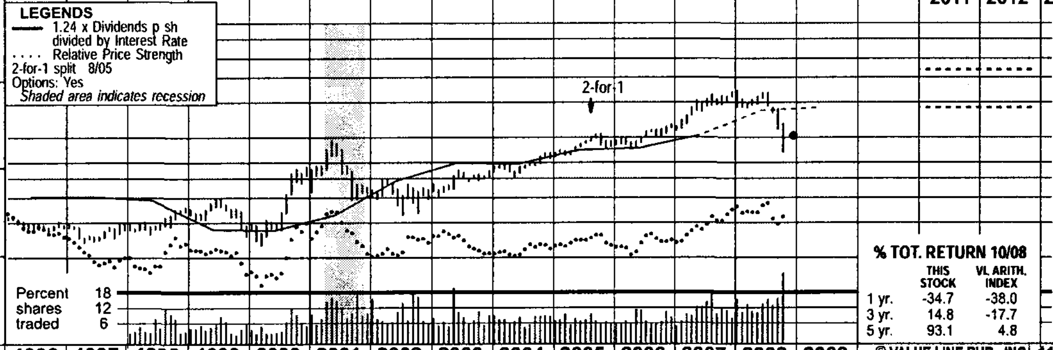
RECENT PRICE 32.67 | P/E RATIO 17.7 (Trailing: 14.4 Median: 12.0) | RELATIVE P/E RATIO 1.74 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 4 Lowered 8/29/08
SAFETY 3 Lowered 11/28/08
TECHNICAL 3 Raised 11/21/08
BETA .80 (1.00 = Market)

High:	12.1	14.5	16.0	23.1	31.2	20.0	22.2	27.1	33.7	37.3	54.6	55.2
Low:	9.5	10.4	10.2	9.2	15.5	13.0	15.8	19.9	25.5	27.8	34.4	26.8

Target Price Range 2011 | 2012 | 2013

LEGENDS
— 1.24 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 8/05
Options: Yes
Shaded area indicates recession



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+115%)	24%
Low	45	(+40%)	12%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	8	1	1	1	2	1	0	0	1
to Sell	2	1	1	2	2	1	0	0	1

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	213	190	224
to Sell	217	246	210
Hld's(000)	228067	234082	237041

Percent shares traded 18 12 6

% TOT. RETURN 10/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-34.7	-38.0
3 yr.	14.8	-17.7
5 yr.	93.1	4.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
9.03	8.96	8.76	8.63	8.94	9.17	12.03	15.97	19.59	19.53	16.38	15.75	15.37	16.36	17.92	17.41	19.10	17.60	Revenues per sh	23.75
1.90	1.98	1.84	2.05	2.14	2.11	2.43	2.56	3.32	3.51	3.20	3.60	3.59	3.84	4.26	5.10	4.75	4.55	"Cash Flow" per sh	8.25
1.01	1.04	.84	.97	1.03	.99	1.12	1.01	1.64	1.79	1.54	1.84	1.87	1.92	2.29	2.63	2.15	1.75	Earnings per sh A	4.50
.80	.83	.84	.84	.84	.84	.67	.50	.53	.53	.72	.77	.82	.96	1.10	1.22	1.34	1.40	Div'd Decl'd per sh B ■	2.25
1.39	1.60	1.62	1.26	1.11	.93	.97	1.11	1.59	2.99	2.74	2.17	1.94	2.13	3.62	4.51	4.30	3.30	Cap'l Spending per sh	3.75
7.79	7.97	7.89	8.15	8.44	8.45	5.69	5.61	6.94	6.33	6.71	9.19	11.21	11.62	13.30	14.88	15.75	16.05	Book Value per sh C	21.75
303.77	304.26	310.96	318.81	325.33	332.50	314.82	287.39	290.08	293.16	331.47	354.72	378.14	380.15	385.04	373.27	374.00	375.00	Common Shs Outst'g D	367.00
12.9	14.1	13.0	10.8	11.4	10.8	10.9	13.4	8.9	12.4	11.1	10.6	12.5	15.1	14.1	17.3	Bold figures are		Avg Ann'l P/E Ratio	13.0
.78	.83	.85	.72	.71	.62	.57	.76	.58	.64	.61	.60	.66	.80	.76	.91	Value Line		Relative P/E Ratio	.85
6.1%	5.7%	7.7%	8.0%	7.1%	7.8%	5.5%	3.7%	3.6%	2.4%	4.2%	4.0%	3.5%	3.3%	3.4%	2.7%	estimates		Avg Ann'l Div'd Yield	3.8%
						3786.0	4590.0	5683.0	5725.0	5429.0	5587.0	5812.0	6219.0	6899.0	6498.0	7150	6600	Revenues ($mill)	8700
						393.0	332.0	500.0	576.0	536.0	667.0	692.0	739.0	899.0	1031.0	830	675	Net Profit ($mill)	1690
						40.7%	33.5%	36.3%	29.7%	25.7%	27.1%	22.8%	14.0%	23.2%	20.7%	30.0%	36.0%	Income Tax Rate	36.0%
						2.3%	2.1%	4.0%	4.3%	3.4%	1.2%	.7%	--	2.6%	--	Nil	Nil	AFUDC % to Net Profit	Nil
						59.1%	65.7%	65.4%	64.8%	66.5%	71.1%	61.6%	57.5%	55.4%	54.1%	53.0%	54.5%	Long-Term Debt Ratio	48.0%
						34.2%	28.2%	29.5%	23.7%	25.1%	28.5%	37.9%	42.0%	42.2%	43.6%	45.0%	43.0%	Common Equity Ratio	50.5%
						5229.0	5716.0	6826.0	7845.0	8868.0	11455	11171	10513	12151	12747	13150	13950	Total Capital ($mill)	15800
						4480.0	5644.0	5948.0	6135.0	9566.0	10446	11209	10916	12069	12605	13250	13450	Net Plant ($mill)	14300
						9.5%	7.9%	9.7%	9.6%	8.8%	7.6%	8.4%	9.3%	9.3%	9.8%	8.0%	6.5%	Return on Total Cap'l	12.5%
						18.4%	16.9%	21.2%	20.8%	18.1%	20.2%	16.1%	16.5%	16.6%	17.6%	13.5%	10.5%	Return on Shr. Equity	20.5%
						20.6%	19.0%	23.6%	28.2%	21.1%	19.6%	16.3%	16.7%	17.3%	18.2%	14.0%	11.0%	Return on Com Equity E	21.0%
						6.4%	9.4%	16.1%	20.2%	12.4%	11.7%	9.3%	8.8%	9.3%	10.0%	5.5%	2.0%	Retained to Com Eq	10.5%
						71%	54%	35%	35%	49%	43%	43%	47%	47%	46%	63%	80%	All Div'ds to Net Prof	50%

CAPITAL STRUCTURE as of 9/30/08
Total Debt $7989.0 mill. **Due in 5 Yrs** $2464.0 mill.
LT Debt $6714.0 mill. **LT Interest** $422.0 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $52.0 mill.
Pension Assets-12/07 $5.60 bill. **Oblig.** $5.48 bill.
Pfd Stock $301.0 mill. **Pfd Div'd** $18.0 mill.
505,189 shs. 3.35%-6.75%, $100 par, cumulative, callable $102.00-$110.00; 10 mill. shs. 6.25%, $100 liq. preference, redeemable after 4/6/11.
Common Stock 374,576,538 shs. **as of 10/31/08**
MARKET CAP: $12 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+4.6	-1.8	+3.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	7035	7554	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+.9	+.7
Fixed Charge Cov. (%)	263	314	330

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	7.0%	-1.5%	5.5%
"Cash Flow"	7.5%	5.5%	11.0%
Earnings	8.5%	6.5%	12.0%
Dividends	2.5%	13.0%	13.0%
Book Value	4.5%	15.0%	8.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1600	1478	1643	1498	6219.0
2006	1781	1642	1752	1724	6899.0
2007	1546	1573	1774	1605	6498.0
2008	1526	1024	2981	1619	7150
2009	1600	1600	1800	1600	6600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.45	.46	.51	.50	1.92
2006	.73	.52	.58	.46	2.29
2007	.57	.62	.87	.57	2.63
2008	.65	.50	.55	.45	2.15
2009	.45	.40	.45	.45	1.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.193	.205	.205	.205	.81
2005	.205	.23	.23	.25	.92
2006	.25	.275	.275	.275	1.08
2007	.275	.305	.305	.305	1.19
2008	.305	.335	.335	.335	

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to about 1.4 million customers in a 10,000-square-mile area in eastern & central Pennsylvania. Plans to sell gas distribution subsidiary. Also has subsidiaries in power generation & marketing, foreign electricity distribution in U.K. (2.6 million customers). Electric revenue breakdown & generating sources not provided by company. Fuel costs: 25% of revenues. '07 depreciation rate: 4.4%. Has 11,100 employees. Chairman, President & CEO: James H. Miller. Incorporated: Pennsylvania. Address: Two North Ninth St., Allentown, Pennsylvania 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

We have lowered our earnings estimates and projections for PPL Corporation. Third-quarter profits were below our expectation due to the company's trading loss on a long power position—which PPL couldn't unwind when liquidity in the power markets temporarily dried up—and the effects of unplanned outages of two coal-fired plants. The forward prices for power have declined materially in recent months, and operating and maintenance expenses are up, so the margins of PPL's power-supply business in the next few years are likely to be lower than we expected. At the same time, interest expense will probably be higher than we expected. All told, we have slashed our share-net estimate from $2.40 to $2.15 for 2008 and from $2.15 to $1.75 for 2009. We have not yet published a profit forecast for 2010, but PPL has reduced its guidance from a range of $4.00-$4.60 a share to $3.60-$4.20. The changing business conditions have prompted the company to trim its 2009 capital budget by $200 million. We have cut our 2011-2013 earnings projection by $0.50 a share and have lowered our dividend growth forecast as well.

Despite the reduced earnings estimates and projections, a sharp bottom-line increase is still in the offing for 2010. That's when customers of PPL Utilities will start paying market-based rates for the generation portion of their bills — power that it provided by PPL's energy-supply business. Under a regulatory agreement that runs through yearend 2009, customers are paying an energy rate that (although increasing each year) is below market prices.

PPL has completed the sale of its gas utility. The sale price was $268 million, plus an adjustment for working capital. This business was sold because it was not strategically significant to PPL.

This equity has fallen around 30% in price since our August report. That's not surprising, given the reduction in the company's earnings guidance. We don't recommend this issue for the year ahead, but it offers moderate long-term recovery potential—as long as PPL can avoid disappointing Wall Street again. Note, though, that we have cut the stock's Safety rank a notch, to 3 (Average).

Paul E. Debbas, CFA *November 28, 2008*

(A) Diluted EPS. Excl. nonrec. gains (losses): '00, 8¢; '01, ($1.18) '02, (89¢); '03, 24¢; '04, 3¢; '05, (2¢); '07, (12¢); gain (losses) on disc. ops.: '03, (6¢); '04, (1¢); '05, (12¢); '07, 19¢; '08, 3¢. Next earnings report due early Feb. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '07: $5.09/sh. (D) In mill., adj. for split. (E) Rate base: Fair value. Rate allowed on com. eq. in '08: none specified; earned on avg. com. eq., '07: 19.2%. Regulatory Climate: Average. (F) Summer peak in '06.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	85

PROGRESS ENERGY NYSE-PGN

RECENT PRICE	P/E RATIO	(Trailing: 13.3 / Median: 15.0)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
38.76	13.5	Trailing: 13.3; Median: 15.0	1.32	6.3%	

TIMELINESS 3 Lowered 7/27/07

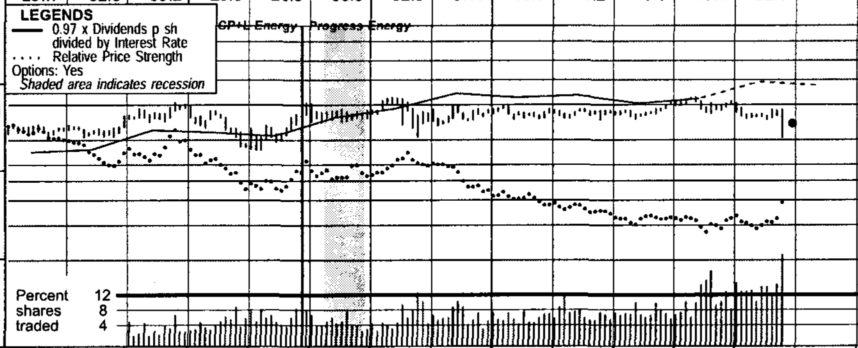
SAFETY 2 Lowered 6/7/02

TECHNICAL 2 Raised 11/28/08

BETA .60 (1.00 = Market)

High:	42.7	49.6	47.9	49.4	49.3	52.7	48.0	47.9	46.0	49.6	52.8	49.2
Low:	32.8	39.2	29.3	28.3	38.8	32.8	37.4	40.1	40.2	40.3	43.1	32.6

LEGENDS
— 0.97 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2011 | 2012 | 2013

120 / 100 / 80 / 64 / 48 / 32 / 24 / 20 / 16 / 12 / 8

2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+30%)	11%
Low	35	(-10%)	4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	1	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	6	1	0	0	0	1	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	216	202	217
to Sell	191	198	183
Hld's(000)	151947	151868	150842

% TOT. RETURN 10/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-13.2	-38.0
3 yr.	6.2	-17.7
5 yr.	19.4	4.8

Progress Energy was formed on November 30, 2000 through the merger of CP&L Energy and Florida Progress. Florida Progress common shareholders exchanged each share held for $54 in cash and/or CP&L common stock. They also received one Contingent Value Obligation for each share of Florida Progress stock, entitling them to payments when four synthetic fuel plants achieved certain economic levels from 2001 to 2007. Data prior to merger are for CP&L only and are not comparable with Progress Energy data.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
20.68	21.04	19.99	38.69	34.18	35.54	39.56	40.11	37.38	35.19	*35.05*	*35.45*	Revenues per sh	*36.10*
6.44	6.06	5.37	8.14	7.02	7.54	7.40	6.53	5.93	6.13	*6.35*	*6.45*	"Cash Flow" per sh	*6.60*
2.75	2.55	2.34	3.43	3.84	3.41	3.10	2.94	2.05	2.69	*2.95*	*3.10*	Earnings per sh A	*3.40*
1.96	2.02	2.08	2.14	2.18	2.26	2.32	2.38	2.42	2.44	*2.46*	*2.48*	Div'd Decl'd per sh B†■	*2.54*
2.80	4.32	4.61	5.56	5.05	4.14	4.04	4.29	5.56	7.59	*7.58*	*8.20*	Cap'l Spending per sh	*7.15*
19.49	21.38	26.32	27.45	28.73	30.26	30.90	31.90	32.37	32.38	*33.30*	*34.00*	Book Value per sh C	*36.45*
151.34	159.60	206.09	218.73	232.43	246.00	247.00	252.00	256.00	260.10	*264.00*	*268.00*	Common Shs Outst'g E	*280.00*
15.9	15.2	15.3	12.4	11.9	12.4	14.1	14.8	21.6	17.9	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*12.5*
.83	.87	.99	.64	.65	.71	.74	.79	1.17	.94	*estimates*		Relative P/E Ratio	*.85*
4.5%	5.2%	5.8%	5.0%	4.8%	5.3%	5.3%	5.5%	5.5%	5.1%			Avg Ann'l Div'd Yield	*6.1%*
3130.1	3357.6	4118.9	8461.5	7945.0	8743.0	9772.0	10108	9570.0	9153.0	*9250*	*9500*	Revenues ($mill)	*10100*
399.2	382.3	369.9	695.1	815.2	818.1	763.5	727.0	514.0	693.0	*780*	*830*	Net Profit ($mill)	*950*
39.2%	40.3%	35.4%	--	--	--	13.1%	--	28.4%	32.5%	*33.0%*	*33.0%*	Income Tax Rate	*33.0%*
1.7%	3.0%	5.6%	2.6%	1.0%	3.4%	.8%	1.8%	1.4%	2.5%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
46.5%	46.6%	51.6%	60.9%	59.0%	56.1%	55.2%	56.2%	51.3%	50.6%	*53.0%*	*52.5%*	Long-Term Debt Ratio	*51.5%*
52.4%	52.5%	47.6%	38.5%	40.4%	43.4%	44.3%	43.3%	48.1%	48.8%	*46.5%*	*47.0%*	Common Equity Ratio	*48.0%*
5623.1	6500.6	11407	15580	16517	17162	17247	18577	17214	17252	*18690*	*19110*	Total Capital ($mill)	*21205*
6299.5	6764.8	10437	10915	10656	14434	14363	14442	15245	16605	*18050*	*19185*	Net Plant ($mill)	*20905*
8.6%	7.3%	4.3%	6.4%	6.8%	6.5%	6.2%	5.6%	4.8%	5.6%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
13.3%	11.0%	6.7%	11.4%	12.0%	10.9%	9.9%	8.9%	6.1%	8.1%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
13.4%	11.1%	6.7%	11.5%	12.1%	10.9%	9.9%	9.0%	6.1%	8.2%	*9.0%*	*9.0%*	Return on Com Equity D	*9.5%*
4.0%	2.5%	NMF	4.3%	5.0%	3.7%	2.6%	1.7%	NMF	.7%	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
71%	78%	101%	63%	59%	67%	74%	81%	119%	91%	*83%*	*80%*	All Div'ds to Net Prof	*75%*

CAPITAL STRUCTURE as of 9/30/08
Total Debt $11230 mill. **Due in 5 Yrs** $3633 mill.
LT Debt $9886 mill. **LT Interest** $538 mill.
(LT interest earned: 2.9x)
Pension Assets-12/07 $2.00 bill. **Oblig.** $2.14 bill.
Pfd Stock $92.8 mill. **Pfd Div'd** $4.5 mill.
921,814 shs. $4.00 to $5.44 cum. no par. callable from $101 to $110 per sh. Sinking funds began in 1984 and 1986, respectively.
Common Stock 263,087,236 shs. **as of 10/31/08**
MARKET CAP: $10.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	1.4	-2.3	+3.5
Avg. Indust. Use (MWH)	2399	2328	2350
Avg. Indust. Revs. per KWH (¢)	5.74	6.38	6.58
Capacity at Peak (Mw)	24500	21322	21776
Peak Load, Summer (Mw)	21983	21717	22327
Annual Load Factor (%)	55.0	NA	NA
% Change Customers (yr-end)	+3.1	+2.0	+3.5
Fixed Charge Cov. (%)	198	204	249

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	6.5%	4.0%	*1.0%*
"Cash Flow"	1.0%	-2.0%	*1.0%*
Earnings	--	-4.5%	*5.0%*
Dividends	3.0%	2.5%	*1.0%*
Book Value	6.0%	3.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	2168	2295	3067	2578	10108
2006	2250	2316	2731	2273	9570
2007	2072	2129	2750	2202	9153
2008	2066	2244	2696	*2244*	*9250*
2009	*2120*	*2230*	*2850*	*2300*	*9500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.43	.03	1.85	.63	2.94
2006	.34	.08	1.12	.51	2.05
2007	.62	.41	1.27	.39	2.69
2008	.58	.77	1.18	*.42*	*2.95*
2009	*.68*	*.60*	*1.32*	*.50*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID ■B† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.575	.575	.575	.575	2.30
2005	.59	.59	.59	.59	2.36
2006	.605	.605	.605	.605	2.42
2007	.61	.61	.61	.61	2.44
2008	.615	.615	.615	.615	

BUSINESS: Progress Energy, parent of CP&L Energy and Florida Progress, supplies electricity to portions of North Carolina, South Carolina, and Florida. Other operations *include coal mining*, wholesale generation, and financial services. Electric revenues: residential, 45%; commercial, 26%; industrial, 13%; other, 16%. Power costs: 47% of revs; labor costs: 14%. Fuel sources: gas/oil/coal, 58%; nuclear, 27%; hydro, less than 1%; purch. power, 14%. Has 11,000 employees. '07 depreciation rate: 2.7%. Est'd plant age: 8 years. Chairman, Chief Executive Officer, and President: William D. Johnson. Incorporated: North Carolina. Address: 411 Fayetteville Street, Raleigh, North Carolina 27602. Telephone: 1-800-662-7232. Internet: www.progress-energy.com.

We have lowered our 2008 and 2009 earnings outlook for Progress Energy. The company posted third-quarter earnings of $1.18 a share, which were below our estimate. Weakness in the Florida economy was evident, with residential and industrial energy sales down 6.1% and 2.7% for the period. The company noted that top-line growth in the region will likely remain weak until the economy recovers. This is *troublesome news for the* energy market as a whole, due to the fact that the state ranks third nationally in per-capita energy consumption. These challenges in Florida partially offset increases in customer growth and usage in the company's Carolina market. This positive driver may indicate a turnaround in the region. All told, we have trimmed a nickel from our share-earnings estimates for both this year and next.

The company's Carolina subsidiary seeks approval for a new generating facility. Progress Energy Carolina (PEC) is scheduled *to begin site preparation* early next year for its new, 600-megawatt, natural gas-fueled plant. The company awaits an air permit from the state before actual construction may begin. The unit will be added to PEC's complex in Richmond County, which already generates about 1,200 megawatts. The plant will likely be used to assist the growing need for energy in the region that, despite the current economic downturn, has had its usage rates and customer growth rise.

The Florida utility commission approved the company's first nuclear cost-recovery filing. Beginning in January, Progress Energy Florida will start collecting about $395 million in preconstruction and licensing costs associated with the Levy County nuclear plant project. Additionally, the company received approval to collect $25 million of costs related to the Crystal River unit 3 upgrade. The commission's decision signifies the region's strong support for the expanded use of nuclear power going forward.

These shares may interest conservative investors. With a yield that is a cut above the industry average, and a secure dividend likely to increase each year, we rate Progress Energy to be a solid utility holding.

Michael Ratty *November 28, 2008*

(A) EPS diluted. Excl. nonrecur.: '00, 69¢; '01, (75¢); '02, ($1.32); '03, (3¢); '05, (39¢); '07, (73¢). Next egs. report due early Feb.
(B) Div'ds historically paid in early Feb., May, Aug, and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan avail.
(C) Incl. def. charges in '07: $17.64/sh.
(D) Rate Base: orig. cost. Rate allowed on common equity. In '88 in N.C.: 12.75%; in '88 in S.C.: 12.75%; in '02 in Fla.: rev. sharing incentive plan; earn. on '07 avg. com. eq.: 8.3%. Regul. Clim.: Avg. (E) In millions.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	10
Earnings Predictability	75

SEMPRA ENERGY NYSE-SRE

RECENT PRICE	42.54	P/E RATIO	10.1 (Trailing: 10.0 Median: 11.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	3.6%	VALUE LINE

High:	27.1	29.3	26.0	24.9	28.6	26.3	30.9	37.9	47.9	57.3	66.4	63.0
Low:	21.4	23.8	17.1	16.2	17.3	15.5	22.3	29.5	35.5	42.9	50.9	34.3

TIMELINESS 4 Lowered 10/24/08

SAFETY 2 Lowered 2/4/00

TECHNICAL 3 Raised 8/8/08

BETA .90 (1.00 = Market)

2011-13 PROJECTIONS

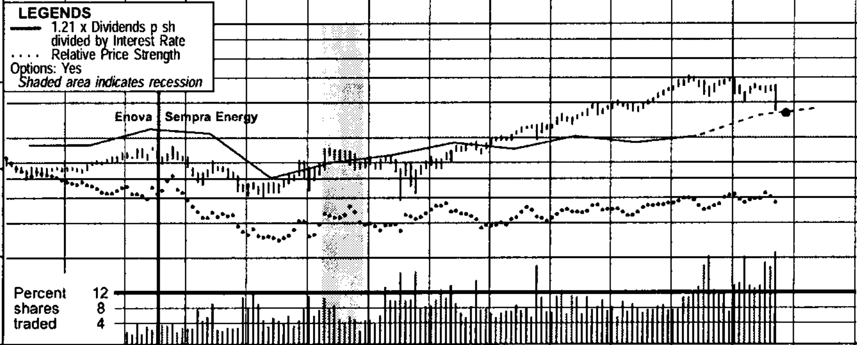
	Price	Gain	Ann'l Total Return
High	90	(+110%)	23%
Low	70	(+65%)	16%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	1	0	0	2
to Sell	0	1	0	0	2	1	0	0	1

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	231	228	174
to Sell	157	194	219
Hld's(000)	176105	174741	174510



% TOT. RETURN 9/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.0	-19.3
3 yr.	15.1	1.5
5 yr.	95.5	43.8

Sempra Energy was formed through the merger of Enova Corp. and Pacific Enterprises on June 26, 1998. Enova stockholders received one Sempra share for each Enova share, and Pacific Enterprises stockholders received 1.5038 Sempra shares for every Pacific Enterprises share.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
23.31	22.89	35.38	39.27	29.38	34.81	40.18	45.64	44.89	43.79	46.55	50.90	Revenues per sh	58.25
5.16	5.36	4.91	5.39	5.71	5.56	6.58	5.96	6.74	6.93	6.95	8.20	"Cash Flow" per sh	10.75
1.24	1.66	2.06	2.55	2.79	3.01	3.93	3.52	4.23	4.26	3.95	4.45	Earnings per sh A	6.00
1.56	1.56	1.00	1.00	1.00	1.00	1.00	1.16	1.20	1.24	1.37	1.60	Div'd Decl'd per sh B ■ †	2.00
1.85	2.48	3.76	5.22	5.92	4.63	4.62	5.46	7.28	7.70	8.55	11.40	Cap'l Spending per sh	10.00
12.29	12.58	12.35	13.17	13.79	17.17	20.78	23.95	28.66	31.87	33.00	34.65	Book Value per sh C	45.75
237.00	237.40	201.90	204.48	204.91	226.60	234.18	257.19	262.01	261.21	245.00	226.00	Common Shs Outst'g D	235.00
21.1	12.8	9.4	9.7	8.2	9.0	8.6	11.8	11.5	14.0	Bold figures are	Value Line estimates	Avg Ann'l P/E Ratio	13.5
1.10	.73	.61	.50	.45	.51	.45	.63	.62	.73			Relative P/E Ratio	.90
6.0%	7.4%	5.2%	4.1%	4.4%	3.7%	2.9%	2.8%	2.5%	2.1%			Avg Ann'l Div'd Yield	2.5%
5525.0	5435.0	7143.0	8029.0	6020.0	7887.0	9410.0	11737	11761	11438	11400	11500	Revenues ($mill)	13700
306.0	405.0	440.0	534.0	586.0	655.0	930.0	898.0	1118.0	1135.0	1010	1085	Net Profit ($mill)	1470
31.1%	30.7%	38.0%	28.8%	19.9%	23.2%	17.2%	--	31.3%	33.6%	40.0%	40.0%	Income Tax Rate	39.0%
3.6%	2.2%	3.6%	5.2%	10.8%	8.4%	2.9%	5.3%	7.2%	11.5%	12.0%	12.0%	AFUDC % to Net Profit	8.0%
47.3%	47.6%	56.2%	55.7%	58.6%	48.4%	45.3%	43.1%	37.0%	34.8%	38.0%	41.0%	Long-Term Debt Ratio	40.0%
49.3%	49.0%	40.4%	41.2%	38.6%	49.0%	52.6%	55.1%	61.4%	63.7%	60.5%	57.5%	Common Equity Ratio	59.0%
5912.0	6092.0	6166.0	6532.0	7312.0	7931.0	9255.0	11178	12229	13071	13325	13650	Total Capital ($mill)	18000
5441.0	5394.0	5726.0	6217.0	6832.0	10474	11086	12101	13175	14884	16275	18075	Net Plant ($mill)	21800
6.8%	8.3%	9.0%	10.2%	9.8%	9.8%	11.3%	9.2%	10.3%	9.6%	8.5%	9.0%	Return on Total Cap'l	9.0%
9.8%	12.7%	16.3%	18.4%	19.3%	16.0%	18.4%	14.1%	14.5%	13.3%	12.0%	13.5%	Return on Shr. Equity	13.5%
10.1%	13.2%	17.2%	19.4%	20.4%	16.6%	18.9%	14.4%	14.8%	13.5%	12.5%	13.5%	Return on Com Equity E	13.5%
NMF	.9%	7.4%	11.9%	13.1%	11.3%	14.9%	10.1%	11.0%	9.7%	8.0%	9.0%	Retained to Com Eq	9.0%
110%	94%	58%	40%	37%	33%	22%	31%	26%	29%	35%	36%	All Div'ds to Net Prof	34%

CAPITAL STRUCTURE as of 6/30/08
Total Debt $5940.0 mill. **Due in 5 Yrs** $2595.0 mill.
LT Debt $4809.0 mill. **LT Interest** $264.0 mill.
(LT interest earned: 7.4x)

Leases, Uncapitalized Annual rentals $120.0 mill.
Pension Assets-12/07 $2.53 bill. **Oblig.** $2.79 bill.

Pfd Stock $179.0 mill. **Pfd Div'd** $9.0 mill.
1,373,770 shs. 4.40%-5% cumulative, $20 par, callable $20.25-$24; 2,040,000 shs. $1.70-$1.82 cum., no par, callable $25.595-$26; 800,000 shs. $4.36-$4.75 cum., no par, callable $100-$101.50; 811,073 shs. 6% cum., $25 par.

Common Stock 246,378,369 shs.
as of 7/31/08
MARKET CAP: $10.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	-.2	+5.3	+.2
Avg. Indust. Use (MWH)	4608	4596	4474
Avg. Indust. Revs. per KWH (¢)	6.58	8.00	10.06
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+1.5	+1.3	+.7
Fixed Charge Cov. (%)	274	409	419

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	10.0%	5.0%	4.5%
"Cash Flow"	3.0%	4.0%	8.5%
Earnings	7.0%	10.0%	7.0%
Dividends	-2.5%	3.5%	9.0%
Book Value	7.5%	16.5%	8.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	2697	2276	2770	3994	11737
2006	3336	2486	2694	3245	11761
2007	3004	2661	2663	3110	11438
2008	3270	2503	2600	3027	11400
2009	3100	2600	2700	3100	11500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.92	.49	.71	1.39	3.52
2006	.90	.71	1.29	1.33	4.23
2007	.86	1.06	1.24	1.10	4.26
2008	.92	.98	1.05	1.00	3.95
2009	1.20	.90	1.20	1.15	4.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.25	.25	.25	.25	1.00
2005	.25	.29	.29	.29	1.12
2006	.29	.30	.30	.30	1.19
2007	.30	.31	.31	.31	1.23
2008	.31	.32	.35	.35	

BUSINESS: Sempra Energy is a holding company for San Diego Gas & Electric Co., which sells electricity and gas mainly in San Diego County, & Southern California Gas Co., which distributes gas to most of Southern California. Customers: 1.4 million electric, 6.5 million gas. Electric revenue breakdown, '07: residential, 45%; commercial, 39%; industrial, 10%; other, 6%. Purchases most of its power; the rest is nuclear and gas. Has various nonutility subsidiaries (54% of '07 earnings). Acq'd EnergySouth 10/08. Power costs: 42% of revenues. '07 deprec. rate: 3.3%. Has 14,300 employees. Chairman & CEO: Donald E. Felsinger. President & COO: Neal E. Schmale. Inc.: California. Address: 101 Ash St., San Diego, CA 92101-3017. Tel.: 619-696-2034. Internet: www.sempra.com.

Sempra Energy is glad that it formed a joint venture earlier this year with Royal Bank of Scotland for its commodities business. This business — largely energy trading and marketing — relies heavily on liquidity and good credit quality. Sempra is benefiting from RBS' larger balance sheet. Had Sempra's business remained independent, it might well be feeling some stress due to the turmoil in the credit markets. In mid-September, Sempra stated that its total exposure to troubled companies in the financial markets is expected to be less than $20 million.

Sempra has completed the acquisition of EnergySouth. Sempra paid $510 million in cash. The key attraction was EnergySouth's two large gas storage facilities, which made a nice addition to the company's midstream gas assets. EnergySouth also has 93,000 utility customers in Alabama. The deal will likely be slightly accretive to earnings in 2009 and might well add as much as $0.30 a share in 2012.

We have increased our 2008 and 2009 earnings estimates. We raised our 2008 estimate by $0.20 a share to reflect the better-than-expected tally in the second quarter. Our revised estimate of $3.95 a share is within Sempra's targeted range of $3.80-$4.00. We have raised our 2009 forecast by a nickel a share, to $4.45, to reflect the EnergySouth purchase. We are still estimating a stock buyback next year, but this is under reconsideration.

The utilities have received rate increases. Rate relief for Southern California Gas and San Diego Gas & Electric should amount to $209 million in 2008 and an average of $95 million a year from 2009 through 2011.

Sempra's gas infrastructure investments are coming on line. The company has a 25% interest in a huge gas pipeline. The western portion is already in service, and the eastern portion is targeted for completion in the second half of 2009. A liquefied natural gas terminal began operations in May, and another is targeted for completion in the first half of 2009. These projects are enhancing the company's earning power.

This stock is untimely, but offers decent risk-adjusted total return potential to 2011-2013.

Paul E. Debbas, CFA *November 7, 2008*

(A) Diluted egs. Excl. nonrec. gain (loss): '05, 17¢; '06, (6¢); gain (losses) from disc. ops.: '04, (10¢); '05, (4¢); '06, $1.21; '07, (10¢). '05 EPS don't add due to rounding. Next egs. report due Nov. 10. (B) Div'ds historically paid mid-Jan., Apr., July, & Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '07: $3.56/sh. (D) In mill. Excl. ESOP shs. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '08, 11.1%; SoCalGas in '03, 10.82%; earned on avg. com. eq., '07: 14.2%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	100
Earnings Predictability	90

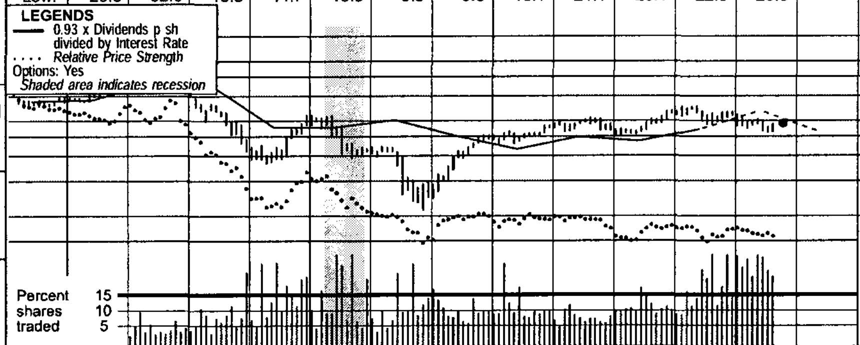
WESTAR ENERGY NYSE-WR

RECENT PRICE 23.32 | P/E RATIO 15.3 (Trailing: 16.4 / Median: 16.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 5.1% | VALUE LINE

TIMELINESS 4 Lowered 8/22/08
SAFETY 2 Raised 4/1/05
TECHNICAL 3 Lowered 5/23/08
BETA .85 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	43.4	44.2	33.9	25.9	25.9	18.0	20.5	22.9	25.0	27.2	28.6	25.9
Low:	29.8	32.6	16.8	14.7	15.6	8.5	9.8	18.1	21.1	20.1	22.8	20.8

Target Price Range 2011 | 2012 | 2013



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+30%)	11%
Low	20	(-15%)	2%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	1	0	0	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	110	110	143
to Sell	80	91	61
Hld's(000)	89472	84983	91814

% TOT. RETURN 8/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-2.3	-9.4
3 yr.	7.3	12.4
5 yr.	58.7	56.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
26.81	30.99	26.26	25.01	31.67	32.90	30.86	30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	17.35	18.60	Revenues per sh	22.55
4.62	5.33	4.98	5.17	5.52	3.47	6.35	7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	4.10	4.40	"Cash Flow" per sh	5.90
2.20	2.76	2.51	2.71	2.60	d.46	2.13	1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.90	1.75	Earnings per sh A	2.00
1.90	1.94	1.98	2.03	2.07	2.10	2.14	2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.24	Div'd Decl'd per sh B■†	1.36
3.49	3.86	3.86	3.77	3.09	3.22	2.77	4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.20	7.55	Cap'l Spending per sh	5.45
21.51	23.08	23.93	24.71	25.14	30.79	29.40	27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.60	21.20	Book Value per sh C	23.15
58.05	61.62	61.62	62.86	64.63	65.41	65.91	67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.40	108.80	Common Shs Outst'g E	110.00
12.9	12.6	11.6	11.7	11.7	--	18.4	17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	Bold figures are		Avg Ann'l P/E Ratio	12.5
.78	.74	.76	.78	.73	--	.96	.98	1.34	--	.76	.62	.92	.79	.66	.74	Value Line		Relative P/E Ratio	.85
6.7%	5.6%	6.8%	6.4%	6.8%	6.3%	5.5%	8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	estimates		Avg Ann'l Div'd Yield	5.4%
						2034.1	2036.2	2368.5	2186.3	1771.1	1461.1	1464.5	1583.3	1605.7	1726.8	1880	2025	Revenues ($mill)	2480
						141.3	100.4	62.7	d40.0	72.0	108.1	100.1	134.9	165.3	168.4	205	190	Net Profit ($mill)	220
						9.3%	--	42.4%	NMF	53.4%	43.1%	25.0%	31.0%	25.4%	27.5%	28.0%	28.0%	Income Tax Rate	28.0%
						--	--	--	--	--	5.0%	--	--	5.0%	10.4%	8.0%	8.0%	AFUDC % to Net Profit	5.0%
						58.4%	60.3%	62.6%	61.8%	71.6%	66.2%	53.8%	52.1%	50.0%	50.6%	49.5%	49.0%	Long-Term Debt Ratio	49.5%
						36.9%	39.2%	36.9%	37.7%	22.9%	33.2%	45.5%	47.2%	49.3%	48.9%	50.0%	50.5%	Common Equity Ratio	50.0%
						5245.9	4783.4	5169.3	4822.4	4272.4	3127.3	3049.2	3000.4	3124.2	3738.3	4445	4575	Total Capital ($mill)	5065
						3795.1	3889.4	3993.4	4042.9	3995.4	3909.5	3911.0	3947.7	4071.6	4803.7	5450	5980	Net Plant ($mill)	6805
						4.3%	4.5%	3.4%	1.5%	4.4%	7.0%	5.5%	6.2%	6.7%	5.8%	6.0%	5.5%	Return on Total Cap'l	5.5%
						6.5%	5.3%	3.2%	NMF	5.9%	10.2%	7.1%	9.4%	10.6%	9.1%	9.0%	8.0%	Return on Shr. Equity	8.5%
						7.1%	5.3%	3.2%	NMF	7.3%	10.3%	7.1%	9.5%	10.7%	9.2%	9.0%	8.5%	Return on Com Equity D	8.5%
						NMF	NMF	NMF	NMF	NMF	4.9%	3.2%	4.3%	5.5%	4.3%	4.0%	2.5%	Retained to Com Eq	2.5%
						102%	NMF	NMF	NMF	120%	53%	56%	55%	49%	53%	61%	71%	All Div'ds to Net Prof	68%

CAPITAL STRUCTURE as of 6/30/08
Total Debt $2220.6 mill. **Due in 5 Yrs** $2073.0 mill.
LT Debt $2040.7 mill. **LT Interest** $102. 3ill.

(LT interest earned: 3.3x)
Pension Assets-12/07 $468 mill. **Oblig.** $578 mill.
Pfd Stock $21.4 mill. **Pfd Div'd** $.9 mill.
121,613 shs. 4 1/2%, callable 108; 54,970 shs. 4 1/4%, callable 101.50; 37,780 shs. 5%, callable 102. All cum. $100 par.

Common Stock 108,153,979 shs. as of 7/31/08
MARKET CAP: $2.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+4.6	+4.8	+2.3
Avg. Indust. Use (MWH)	1233	1248	1235
Avg. Indust. Revs. per KWH (¢)	4.34	4.58	4.55
Capacity at Peak (Mw)	5851	6033	6178
Peak Load, Summer (Mw)	4549	4914	4836
Annual Load Factor (%)	55.5	54.0	54.5
% Change Customers (yr-end)	+1.1	+1.2	+1.0
Fixed Charge Cov. (%)	255	291	302

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	-5.0%	-9.5%	3.5%
"Cash Flow"	-2.5%	-8.5%	8.5%
Earnings	1.0%	32.0%	2.0%
Dividends	-7.0%	-5.0%	5.5%
Book Value	-4.0%	-4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	336.5	374.8	477.9	394.1	1583.3
2006	340.0	406.6	515.9	343.2	1605.7
2007	370.3	415.2	548.5	392.8	1726.8
2008	406.8	451.2	590	432	1880
2009	440	485	630	470	2025

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.18	.32	.97	.08	1.55
2006	.30	.40	1.03	.15	1.88
2007	.34	.36	.99	.15	1.84
2008	.63	.06	1.05	.16	1.90
2009	.25	.25	1.10	.15	1.75

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.19	.19	.19	.19	.76
2005	.23	.23	.23	.23	.92
2006	.23	.25	.25	.25	.98
2007	.25	.27	.27	.27	1.06
2008	.27	.29	.29		

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Power & Light. It supplies electricity to 674,000 customers in east Kansas. Electric revenue sources: residential and rural, 41%; commercial, 37%; industrial, 22%; misc.: less than 1%. Acquired Kansas Gas & Electric Co. 3/92. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in February, 2004. 2007 depreciation rate: 2.7%. Estimated plant age: 16 years. Fuels: coal; 56%; nuclear: 9%; gas: 34%.; other, 1%. Labor costs: 17%. Has 2,323 employees. Chairman: Charles Q. Chandler IV. C.E.O. & President: William B. Moore. Inc.: Kansas. Address: 818 Kansas Avenue, P.O. Box 889, Topeka, Kansas 66601. Tel.: 785-575-8227. Internet: www.wr.com.

Westar Energy plans expansion of its transmission system to improve the flow of power in Kansas. It has begun constructing a 345-kilovolt (kv), 97-mile line that will run from Wichita to Salina. The line will be built in two phases. The first sector is scheduled for completion by the end of 2008. The second should begin operation one year later. The cost, including the addition of a substation, is estimated at $80 million to $100 million. The line will allow development of new wind-driven plants in the area. Westar has also formed a joint venture with Electric Transmission America to construct a 765-kv, 230-mile line from Wichita south to the Oklahoma border. The project would provide utilities statewide with greater access to wholesale power markets. Regulators are expected to decide by yearend whether the partnership or a competitor will be permitted to proceed with the venture.

The company awaits an order on a filing for increased rates. It seeks a $90.0 million hike in its northern region and $87.6 million in the southern region. The request relates primarily to its $1.2 billion investment in new generation and transmission and distribution lines since rates were last calculated in 2004. WR also needs recovery of the $69 million cost of last December's destructive ice storm. Recoupment of the planned $660 million expenditure on emission controls over the next three years is not included in the rate case. This outlay will be paid by customers through a separate environmental charge. A regulatory decision on the application is due next January.

A one-time first-quarter federal tax credit of $0.40 a share should lift 2008 earnings marginally. Without this positive, we estimate earnings would fall 18%, to $1.50 a share, because of more shares outstanding. Despite the benefit of an order on the pending rate case, next year's earnings may remain below those of 2008, due to the absence of the tax credit. The shares are untimely.

The stock offers an even balance of pluses and minuses. The above-average yield might interest income-oriented investors. But those of a conservative bent might look elsewhere until a dispute with two former executives is resolved.

Arthur H. Medalie *September 26, 2008*

(A) EPS basic. Excl. nonrecur gains (losses): '94, $0.31; '96, ($0.19); '97 net, $7.97; '98, ($1.45); '99, ($1.31); '00, $1.07; '01, 27¢, '02, ($12.06); '03 net, 77¢. Next egs. rep't due late Oct. (B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. in '07: $6.04/sh. (D) Rate base deter.: fair value; rate all'd on com. eq. (elect.) in '06: 10.0%. Earned on avg. com. eq. in '07: 9.8%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	25

WISCONSIN ENERGY NYSE-WEC

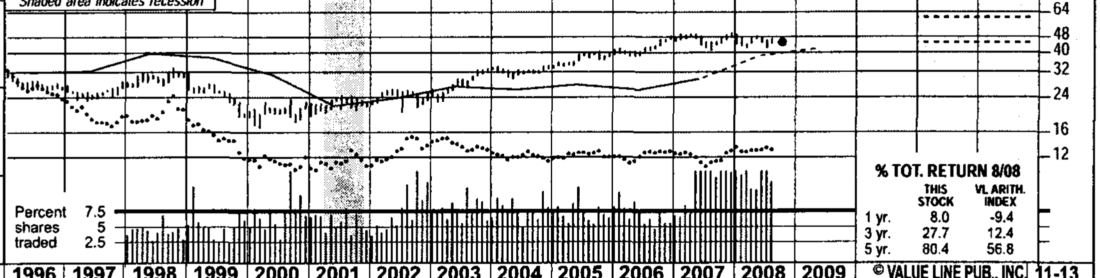
RECENT PRICE **45.30** | P/E RATIO **15.8** (Trailing: 15.0; Median: 15.0) | RELATIVE P/E RATIO **1.04** | DIV'D YLD **2.6%** | VALUE LINE

TIMELINESS 3 Raised 11/9/07
SAFETY 2 Lowered 7/11/97
TECHNICAL 3 Lowered 5/30/08
BETA .75 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	29.1	34.0	31.6	23.6	24.6	26.5	33.7	34.6	40.8	48.7	50.5	49.6
Low:	23.0	27.0	19.1	16.8	19.1	20.2	22.6	29.5	33.3	38.2	41.1	42.0

Target Price Range 2011 | 2012 | 2013

LEGENDS
— 1.36 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+30%)	10%
Low	45	(Nil)	3%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	1	1	0	0	3	1	0
to Sell	1	0	1	1	0	0	2	1	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	134	121	138
to Sell	118	117	103
Hld's(000)	80075	81614	80165

% TOT. RETURN 8/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.0	-9.4
3 yr.	27.7	12.4
5 yr.	80.4	56.8

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
15.05	15.61	15.99	15.98	15.88	15.86	17.13	19.11	28.28	34.04	32.20	34.24	29.33	32.62	34.17	36.24	*38.90*	*41.25*	Revenues per sh	*49.50*
3.22	3.84	3.81	4.28	4.25	2.96	4.13	4.53	4.48	5.44	5.68	5.71	5.16	5.78	5.80	5.97	*5.90*	*6.45*	"Cash Flow" per sh	*8.50*
1.67	1.81	1.67	2.13	1.97	.54	1.65	1.88	1.08	1.84	2.32	2.26	1.85	2.56	2.64	2.84	*2.85*	*3.10*	Earnings per sh A	*4.25*
1.29	1.34	1.40	1.46	1.51	1.54	1.56	1.56	1.37	.80	.80	.80	.83	.88	.92	1.00	*1.08*	*1.24*	Div'd Decl'd per sh B ■ †	*1.60*
3.11	3.43	2.76	2.50	3.53	3.13	3.52	4.44	5.29	6.03	5.07	5.89	5.70	6.79	8.35	10.56	*10.45*	*7.20*	Cap'l Spending per sh	*7.25*
14.97	15.67	16.01	16.89	17.42	16.51	16.46	16.89	17.00	17.81	18.44	19.92	21.31	22.91	24.70	26.50	*28.00*	*29.55*	Book Value per sh C	*36.00*
103.09	105.32	108.94	110.82	111.68	112.87	115.61	118.90	118.65	115.42	116.03	118.43	116.99	116.98	116.97	116.94	*117.00*	*117.00*	Common Shs Outst'g D	*117.00*
15.6	15.2	15.2	13.1	14.3	47.3	18.0	13.3	18.7	12.1	10.5	12.4	17.5	14.5	16.0	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.95	.90	1.00	.88	.90	2.73	.94	.76	1.22	.62	.57	.71	.92	.77	.86	.87	*Value Line*		Relative P/E Ratio	*.85*
5.0%	4.9%	5.5%	5.2%	5.4%	6.0%	5.2%	6.3%	6.8%	3.6%	3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 6/30/08
Total Debt $4457.0 mill. **Due in 5 Yrs** $1870.7 mill.
LT Debt $3126.6 mill. **LT Interest** $187.6 mill.
Incl. $154.1 mill. capitalized leases.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $37.0 mill.

Pension Assets-12/07 $1.01 bill. **Oblig.** $1.16 bill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable at $101;
44,498 shs. 6%, $100 par.
Common Stock 116,919,941 shs.

MARKET CAP: $5.3 billion (Large Cap)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
1980.0	2272.6	3354.7	3928.5	3736.2	4054.3	3431.1	3815.5	3996.4	4237.8	*4550*	*4825*	Revenues ($mill)	*5800*
189.3	231.5	132.0	218.8	270.8	269.2	221.2	304.8	313.7	337.7	*340*	*370*	Net Profit ($mill)	*505*
32.7%	33.8%	43.7%	40.9%	37.4%	35.5%	37.5%	32.9%	35.8%	39.1%	*38.5%*	*39.0%*	Income Tax Rate	*39.0%*
5.7%	5.8%	12.3%	6.9%	4.1%	6.9%	10.0%	12.5%	19.0%	23.8%	*15.0%*	*14.0%*	AFUDC % to Net Profit	*8.0%*
47.5%	48.8%	58.9%	62.2%	59.8%	59.9%	56.2%	52.8%	51.3%	50.3%	*51.5%*	*51.5%*	Long-Term Debt Ratio	*48.5%*
51.7%	45.9%	40.5%	37.2%	39.6%	39.6%	43.3%	46.7%	48.2%	49.2%	*48.0%*	*48.0%*	Common Equity Ratio	*51.0%*
3682.6	4372.8	4979.9	5523.8	5400.3	5963.3	5762.3	5741.5	5992.8	6302.1	*6830*	*7210*	Total Capital ($mill)	*8250*
3238.4	3846.6	4152.4	4188.0	4398.8	5926.1	5903.1	6362.9	7052.5	7681.2	*8545*	*9000*	Net Plant ($mill)	*10225*
6.6%	6.7%	4.7%	5.8%	7.1%	6.3%	5.6%	7.0%	6.6%	7.0%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
9.8%	10.3%	6.4%	10.5%	12.5%	11.3%	8.8%	11.2%	10.7%	10.8%	*10.0%*	*10.5%*	Return on Shr. Equity	*12.0%*
9.9%	10.9%	6.5%	10.6%	12.6%	11.4%	8.8%	11.3%	10.8%	10.9%	*10.5%*	*10.5%*	Return on Com Equity E	*12.0%*
.6%	1.9%	NMF	6.0%	8.3%	7.4%	4.9%	7.5%	7.1%	7.1%	*6.5%*	*6.5%*	Retained to Com Eq	*7.5%*
94%	84%	NMF	43%	35%	35%	45%	34%	35%	35%	*38%*	*39%*	All Div'ds to Net Prof	*37%*

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+3.8	-4.0	+2.2
Avg. Indust. Use (MWH)	16578	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.15	5.80	6.02
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6344	6376	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+.9	+.2
Fixed Charge Cov. (%)	277	260	258

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	8.0%	1.5%	6.5%
"Cash Flow"	4.5%	2.5%	6.5%
Earnings	5.5%	9.0%	8.0%
Dividends	-4.5%	-1.0%	9.5%
Book Value	4.0%	7.0%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	1094.7	788.5	797.3	1135.0	3815.5
2006	1247.0	814.4	839.8	1095.2	3996.4
2007	1301.1	906.5	881.5	1148.7	4237.8
2008	1431.8	946.1	*950*	*1222.1*	*4550*
2009	*1525*	*1000*	*1025*	*1275*	*4825*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.76	.48	.56	.77	2.56
2006	.88	.50	.60	.65	2.64
2007	.85	.49	.70	.80	2.84
2008	1.04	.49	*.53*	*.79*	*2.85*
2009	*1.05*	*.55*	*.65*	*.85*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.20	.21	.21	.21	.83
2005	.22	.22	.22	.22	.88
2006	.23	.23	.23	.23	.92
2007	.25	.25	.25	.25	1.00
2008	.27	.27	.27		

BUSINESS: Wisconsin Energy Corporation (WEC) is a holding company for We Energies, which provides electric, gas & steam service in WI & upper MI. Customers: 1.1 mill. elec., 1 mill. gas. Acq'd Edison Sault Electric 5/98; WICOR 4/00. Discontinued pump-manufacturing ops. in '04. Sold Point Beach nuclear plant in '07. Electric rev. breakdown, '07: residential, 34%; small commercial & industrial, 32%; large comm'l & ind'l, 25%; other, 9%. Generating sources, '07: coal, 54%; nuclear, 17%; gas, 6%; hydro, 1%; purch., 22%. Fuel costs: 48% of revs. '07 reported depr. rate (utility): 3.7%. Has 5,000 empls. Chairman, Pres. & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 2949, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

Wisconsin Energy has resolved all environmental challenges to the two coal-fired units it is building under its "Power the Future" program. Under Power the Future, a nonregulated subsidiary, We Power, is constructing two gas-fired units and two coal-fired units and leasing them to We Energies, Wisconsin Energy's utility subsidiary. The leasing agreements are designed to produce an attractive 12.7% return on equity. This enhances Wisconsin Energy's earning power. The gas-fired facilities went into service in 2005 and 2008. The coal-fired facilities raised a lot of opposition, and the company faced some litigation. It has settled all such matters. The coal plants are expected to come on line in December of 2009 and August of 2010. The first facility was supposed to begin commercial operation next September, and the three-month delay will hurt Wisconsin Energy's earnings next year by an estimated $0.09 a share. We have lowered our 2009 share-earnings forecast from $3.25 to $3.10.

The company is facing higher fuel costs. Unlike in many states, utilities in Wisconsin have some exposure to fuel costs when prices are rising. Even though We Energies received a $118.9 million rate hike this year to recover higher fuel costs, the company will probably swallow at least $20 million (pretax) of these expenses in 2008. The current surge in the cost of coal will likely hurt pretax profits by $15 million in 2009. That's reflected in our revised earnings estimate that was mentioned above.

The company is active in the regulatory arena. Besides the aforementioned fuel-recovery rate increase, Wisconsin Electric is seeking a tariff hike of $22.0 million (14.7%) in Michigan. An order is expected by yearend. The utility plans to file rate cases in Wisconsin and Michigan in 2009. Another fuel filing is possible next year if the company doesn't recover all of its fuel expenses again.

We continue to believe that this stock is expensively priced. Its yield is one of the lowest of any utility equity. Despite our projection of good earnings and dividend growth over the 3- to 5-year period, the stock's total return potential over that time is only average for a utility.

Paul E. Debbas, CFA *September 26, 2008*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (9¢); '00, 19¢ net; '01, 1¢ net; '02, (88¢); '03, (20¢) net; '04, (81¢); gains on disc. ops.: '04, $1.54; '05, 4¢; '06, 4¢. '05 & '06 earnings don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '07: $12.00/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '08: 10.75%; earned on avg. com. eq., '07: 11.1%. Regulat. Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	75

XCEL ENERGY NYSE-XEL

RECENT PRICE	17.32	P/E RATIO	12.1 (Trailing: 12.3 / Median: 15.0)	RELATIVE P/E RATIO	1.09	DIV'D YLD	5.6%	VALUE LINE

TIMELINESS 3 Lowered 3/16/07
SAFETY 2 Raised 5/14/04
TECHNICAL 3 Raised 8/8/08
BETA .75 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	29.4	30.8	27.9	30.0	31.8	28.5	17.4	18.8	20.2	23.6	25.0	22.9
Low:	22.3	25.7	19.3	16.1	24.2	5.1	10.4	15.5	16.5	17.8	19.6	15.3

Target Price Range 2011 | 2012 | 2013

2011-13 PROJECTIONS

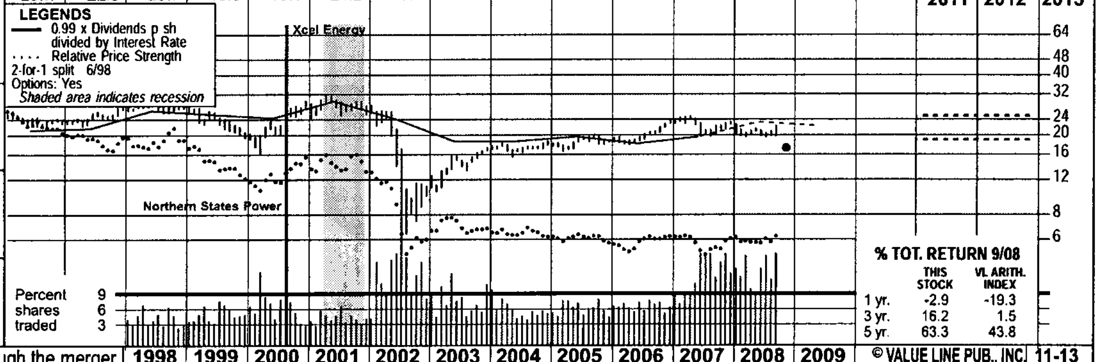
	Price	Gain	Ann'l Total Return
High	25	(+45%)	14%
Low	19	(+10%)	8%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	1	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2007	1Q2008	2Q2008
to Buy	197	167	195
to Sell	157	175	138
Hld's(000)	265057	254808	253197



% TOT. RETURN 9/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-2.9	-19.3
3 yr.	16.2	1.5
5 yr.	63.3	43.8

Xcel Energy was formed through the merger of Northern States Power and New Century Energies on August 21, 2000. NSP stockholders received one share of Xcel for every NSP share, and NCE stockholders received 1.55 shares of Xcel for each NCE share. Data prior to 2000 reflect NSP on a stand-alone basis and are not comparable with Xcel data.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
18.46	18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	*24.85*	*25.45*	Revenues per sh	*29.75*
4.30	4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	*3.55*	*3.70*	"Cash Flow" per sh	*4.50*
1.84	1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	*1.45*	*1.50*	Earnings per sh A	*2.00*
1.43	1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	*.94*	*.97*	Div'd Decl'd per sh B ■	*1.06*
2.99	13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	*4.70*	*3.55*	Cap'l Spending per sh	*4.50*
16.25	16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	*15.30*	*15.85*	Book Value per sh C	*18.00*
152.70	155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	*449.00*	*451.50*	Common Shs Outst'g D	*458.00*
15.2	16.6	14.3	12.4	40.8	11.6	13.6	15.4	14.8	16.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*11.0*
.79	.95	.93	.64	2.23	.66	.72	.82	.80	.88	*estimates*		Relative P/E Ratio	*.75*
5.1%	6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%			Avg Ann'l Div'd Yield	*4.8%*
2819.2	2869.0	11592	15028	9524.4	7937.5	8345.3	9625.5	9840.3	10034	*11150*	*11500*	Revenues ($mill)	*13600*
298.1	240.1	545.8	784.7	177.6	510.0	526.9	499.0	568.7	575.9	*645*	*680*	Net Profit ($mill)	*885*
26.0%	21.6%	35.8%	28.2%	32.7%	23.7%	23.2%	25.8%	24.2%	33.8%	*34.0%*	*33.5%*	Income Tax Rate	*34.0%*
5.3%	2.5%	4.4%	7.1%	46.7%	8.9%	10.9%	8.5%	9.8%	12.5%	*16.0%*	*11.0%*	AFUDC % to Net Profit	*12.0%*
39.9%	54.7%	58.8%	66.7%	59.6%	55.3%	55.0%	51.7%	52.1%	49.7%	*52.0%*	*51.5%*	Long-Term Debt Ratio	*51.0%*
53.5%	40.5%	40.5%	32.8%	39.5%	43.8%	44.1%	47.3%	47.0%	49.4%	*47.5%*	*48.0%*	Common Equity Ratio	*48.5%*
4637.7	6316.2	13745	18911	11815	11790	11801	11398	12371	12748	*14450*	*14950*	Total Capital ($mill)	*17100*
4395.2	4451.5	15273	21165	18816	13667	14096	14696	15549	16676	*17825*	*18425*	Net Plant ($mill)	*20900*
8.1%	5.4%	6.0%	6.0%	5.4%	6.1%	6.2%	6.2%	6.2%	6.3%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
10.7%	8.4%	9.6%	12.5%	3.7%	9.7%	9.9%	9.1%	9.6%	9.0%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.5%*
11.2%	8.6%	9.7%	12.6%	3.7%	9.8%	10.0%	9.2%	9.7%	9.1%	*9.5%*	*9.5%*	Return on Com Equity E	*10.5%*
2.5%	NMF	.9%	4.3%	NMF	3.9%	3.9%	2.9%	3.6%	3.1%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
79%	100%	91%	66%	NMF	60%	62%	69%	63%	66%	*65%*	*65%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 6/30/08
Total Debt $8553.5 mill. **Due in 5 Yrs** $3631.0 mill.
LT Debt $7139.6 mill. **LT Interest** $464.1 mill.
Incl. 8,000,000 shares 7.875% tax-deductible Trust Originated Preferred Securities, liquidation value $25/share; 7,760,000 shares 7.60%, cumulative, $25 par; $100 mill. 7.85% tax-deductible Trust Preferred Securities.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $104.6 mill.
Pension Assets-12/07 $3.19 bill. **Oblig.** $2.66 bill.
Pfd Stock $105.0 mill. **Pfd Div'd** $4.2 mill.
1,049,800 shares $3.60 to $4.56, cumulative, $100 par, callable $102.00 to $103.75.
Common Stock 431,004,383 shs. as of 7/31/08
MARKET CAP: $7.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+3.6	+1.8	+2.0
Avg. C & I Use (MWH)	150	153	153
Avg. C & I Revs. per KWH (¢)	6.22	6.55	6.57
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20854	21255	21108
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.4	+1.2	+.9
Fixed Charge Cov. (%)	232	238	256

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	2.5%	-7.0%	4.0%
"Cash Flow"	-2.0%	-3.5%	4.5%
Earnings	-3.5%	-2.0%	7.5%
Dividends	-4.5%	-8.5%	3.0%
Book Value	-1.0%	-1.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	2381	2074	2289	2882	9625.5
2006	2888	2074	2411	2467	9840.3
2007	2764	2267	2400	2603	10034
2008	3028	2616	2852	*2654*	*11150*
2009	*3000*	*2750*	*2900*	*2850*	*11500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.18	.47	.24	1.20
2006	.36	.24	.53	.23	1.35
2007	.28	.16	.59	.31	1.35
2008	.35	.24	.51	*.35*	*1.45*
2009	*.33*	*.27*	*.55*	*.35*	*1.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.188	.188	.208	.208	.79
2005	.208	.208	.215	.215	.85
2006	.215	.215	.223	.223	.88
2007	.223	.223	.23	.23	.91
2008	.23	.23	.238		

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies power to Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, & gas to Minnesota, Wisconsin, North Dakota, & Michigan; Public Service of Colorado, which supplies power & gas to Colorado; & Southwestern Public Service, which supplies power to Texas & New Mexico. Customers: 3.3 mill. electric, 1.8 mill. gas. Electric revenue breakdown, '07: residential, 29%; commercial & industrial, 52%; other, 19%. Generating sources not available. Fuel costs: 57% of revs. '07 reported deprec. rate: 3.2%. Has 10,900 employees. Chairman, President & CEO: Richard C. Kelly. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

We have trimmed our 2008 and 2009 earnings estimates for Xcel Energy by a nickel a share each year. Electric sales have trended below the company's expectation at Northern States Power (NSP), Xcel's utility in Minnesota. Since this is a reflection of the economic weakness in the service area, this trend isn't likely to improve in the near term. Moreover, average shares outstanding will be higher than we had expected as a result of the sale of 17.25 million common shares in September. And borrowing costs might well be higher in the next several months. Upon announcing third-quarter earnings, Xcel narrowed its 2008 share-net target from $1.45-$1.55 to $1.45-$1.50 and stated, "we now expect to be at the low-end of the . . . range."

Xcel continues to be active in the regulatory arena. That's why we continue to look for earnings to advance in 2009. In New Mexico, Southwestern Public Service (SPS) received a rate increase of $10.8 million (4.1%) based on a 10.8% return on equity. In Texas, SPS is seeking an electric tariff hike of $94.4 million (9.1%) based on an 11.25% return on a 51.0% common-equity ratio. Various intervenors are recommending lower increases and lower allowed ROEs. An order is expected in early 2009. In North Dakota, NSP is seeking an electric rate increase of $17.9 million (12.2%), based on a 10.75% return on a common-equity ratio of 51.77%. New tariffs are expected to take effect in the first quarter of 2009. The company is planning to file electric rate cases in Colorado and Minnesota, but hasn't determined the timing of the applications.

Finances are in good shape. The timing of the aforementioned equity offering was propitious, since it occurred before the stock market's steep downturn. No additional equity, except for some $40 million a year from the dividend reinvestment program, will be needed anytime soon. As of October 21st, Xcel had $1.9 billion of liquidity, which is ample.

Xcel stock offers an attractive yield, which is high even for a utility. The stock has fallen less than most utility issues during the market's decline, however, so total return potential to 2011-2013 is below average.

Paul E. Debbas, CFA *November 7, 2008*

(A) Diluted EPS. Excl. nonrec. loss: '02, $6.27; gains (losses) on discont. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢. '06 & '07 EPS don't add due to rounding. Next earnings report due late Jan. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '07: $3.93/sh. (D) In mill., adj. for split. (E) Rate base: Varies. Rate all'd on com. eq.: MN '93, 11.47%; WI '08, 10.75%; CO '03 (elec.), 10.75%; CO '07 (gas) 10.25%; TX '86, 15.05%; earned on avg. com. eq., '07: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	15
Earnings Predictability	45

ATTACHMENT B

ZACKS INVESTMENT RESEARCH
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ALLETE INC (NYSE)					Scottrade
ALE	34.31	▾-0.50	(-1.44%)	Vol. 228,697	13:04 ET

ALLETE is a multi-services company. ALLETE's holdings include the one of the largest wholesale automobile auction networks in North America; a provider of independent auto dealer inventory financing; one of the largest investor-owned water utilities in Florida and North Carolina; significant real estate holdings in Florida and a low-cost electric utility that serves some of the largest industrial customers in the United States. (Company Press Release)

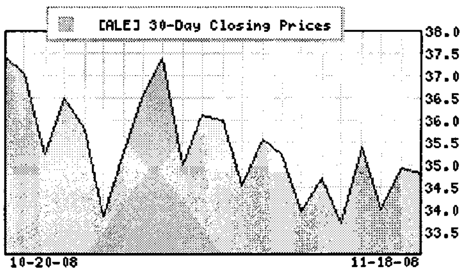
General Information

ALLETE INC
30 West Superior Street
Duluth, MN 55802-2093
Phone: 218-279-5000
Fax: 218-723-3944
Web: www.allete.com
Email: tthorp@allete.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/06/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	34.81
52 Week High	49.00
52 Week Low	31.63
Beta	0.77
20 Day Moving Average	397,604.59
Target Price Consensus	48.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.02	4 Week	4.47
12 Week	-17.41	12 Week	22.23
YTD	-12.05	YTD	44.44

Share Information		Dividend Information	
Shares Outstanding (millions)	30.98	Dividend Yield	4.94%
		Annual Dividend	$1.72
Market Capitalization (millions)	1,078.28	Payout Ratio	0.61
Short Ratio	8.07	Change in Payout Ratio	0.04
Last Split Date	09/21/2004	Last Dividend Payout / Amount	11/12/2008 / $0.43

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.86	Current (1=Strong Buy, 5=Strong Sell)	1.50
Current Year EPS Consensus Estimate	2.84	30 Days Ago	1.60
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	1.60
Next EPS Report Date	02/06/2009	90 Days Ago	1.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.26	vs. Previous Year	46.55%	vs. Previous Year	0.45%
Trailing 12 Months:	12.39	vs. Previous Quarter	129.73%	vs. Previous Quarter:	6.27%
PEG Ratio	2.45				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.35	09/30/08	10.64	09/30/08	4.64

Price/Cash Flow	7.88	06/30/08	9.81	06/30/08	4.30
Price / Sales	1.32	03/31/08	11.58	03/31/08	5.12
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	1.62	09/30/08	1.18	09/30/08	9.94
06/30/08	1.68	06/30/08	1.31	06/30/08	8.94
03/31/08	1.69	03/31/08	1.32	03/31/08	9.99
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	15.15	09/30/08	15.15	09/30/08	25.82
06/30/08	14.13	06/30/08	14.13	06/30/08	24.62
03/31/08	15.55	03/31/08	15.55	03/31/08	24.37
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	6.16	09/30/08	0.67	09/30/08	40.61
06/30/08	6.72	06/30/08	0.71	06/30/08	41.91
03/31/08	7.32	03/31/08	0.63	03/31/08	38.96

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ALLIANT ENERGY CORP (NYSE)

Scottrade

LNT	30.68	▼-0.43	(-1.38%)	Vol. 558,763	13:19 ET

Alliant Energy Corp. is a growing energy-services provider with operations both domestically and internationally. Alliant Energy provides electric, natural gas, water and steam services to customers worldwide. Alliant Energy Resources, Inc., the home of the company's non-regulated businesses, has operations and investments throughout the United States as well as in Australia, Brazil, China, Mexico and New Zealand. (Company Press Release)

General Information

ALLIANT ENGY CP
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Madison, WI 53718
Phone: 608-458-3311
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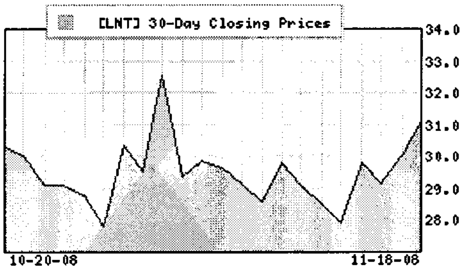
Web: www.alliantenergy.com
Email: customercare@alliantenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/04/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.11
52 Week High	43.41
52 Week Low	22.80
Beta	0.70
20 Day Moving Average	1,020,818.38
Target Price Consensus	38



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.67	4 Week	15.24
12 Week	-10.55	12 Week	32.38
YTD	-23.54	YTD	20.54

Share Information		Dividend Information	
Shares Outstanding (millions)	110.45	Dividend Yield	4.50%
		Annual Dividend	$1.40
Market Capitalization (millions)	3,436.10	Payout Ratio	0.53
Short Ratio	0.67	Change in Payout Ratio	0.01
Last Split Date	N/A	Last Dividend Payout / Amount	10/29/2008 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.59	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	2.63	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	6.10	60 Days Ago	2.00
Next EPS Report Date	02/04/2009	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.85	vs. Previous Year	-5.71%	vs. Previous Year	8.05%
Trailing 12 Months:	11.83	vs. Previous Quarter	110.64%	vs. Previous Quarter:	18.48%
PEG Ratio	1.94				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.22	09/30/08	10.57	09/30/08	3.98

Price/Cash Flow	5.98	06/30/08	11.13	06/30/08	4.13
Price / Sales	0.94	03/31/08	11.14	03/31/08	4.13
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	1.07	09/30/08	0.84	09/30/08	7.88
06/30/08	1.28	06/30/08	1.12	06/30/08	8.24
03/31/08	1.55	03/31/08	1.39	03/31/08	8.24
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	18.16	09/30/08	18.16	09/30/08	25.47
06/30/08	18.66	06/30/08	18.66	06/30/08	24.85
03/31/08	19.47	03/31/08	19.47	03/31/08	24.62
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	14.86	09/30/08	0.45	09/30/08	34.79
06/30/08	14.39	06/30/08	0.51	06/30/08	31.98
03/31/08	13.77	03/31/08	0.52	03/31/08	32.20

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AMEREN CORP (NYSE)

Scottrade

AEE	32.99	▼-0.55	(-1.64%)	Vol. 688,962	13:20 ET

Ameren Corporation companies provide energy services customers in Missouri and Illinois. AmerenUE, one of its subsidiaries, is the one of the largest electric utilities in Missouri and distributors of natural gas. AmerenCIPS, another subsidiary, is both an electric and natural gas utility and serves one of the largest geographic areas of Illinois-based utility companies. (Company Press Release)

General Information

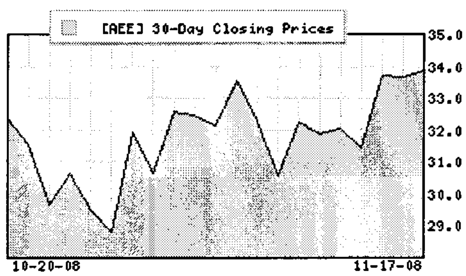
AMEREN CORP
1901 Chouteau Avenue
St. Louis, MO 63103
Phone: 314-621-3222
Fax: 314-621-2888
Web: www.ameren.com
Email: invest@ameren.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/05/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.54
52 Week High	54.74
52 Week Low	25.51
Beta	0.88
20 Day Moving Average	1,543,388.75
Target Price Consensus	37.83



% Price Change		% Price Change Relative to S&P 500	
4 Week	6.37	4 Week	18.25
12 Week	-20.52	12 Week	17.63
YTD	-38.13	YTD	4.43

Share Information		Dividend Information	
Shares Outstanding (millions)	210.21	Dividend Yield	7.57%
		Annual Dividend	$2.54
Market Capitalization (millions)	7,050.38	Payout Ratio	0.82
Short Ratio	1.52	Change in Payout Ratio	-0.03
Last Split Date	N/A	Last Dividend Payout / Amount	09/08/2008 / $0.63

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.37	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.89	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	3.00
Next EPS Report Date	02/05/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.60	vs. Previous Year	-13.97%	vs. Previous Year	3.15%
Trailing 12 Months:	10.85	vs. Previous Quarter	74.63%	vs. Previous Quarter:	15.21%
PEG Ratio	2.32				

Price Ratios		ROE		ROA	
Price/Book	1.00	09/30/08	9.64	09/30/08	3.12

Price/Cash Flow	4.76	06/30/08	10.27	06/30/08	3.33
Price / Sales	0.91	03/31/08	10.36	03/31/08	3.38
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.87	09/30/08	0.55	09/30/08	8.53
06/30/08	0.90	06/30/08	0.67	06/30/08	9.06
03/31/08	0.66	03/31/08	0.50	03/31/08	9.15
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	13.82	09/30/08	13.82	09/30/08	33.51
06/30/08	14.65	06/30/08	14.65	06/30/08	32.54
03/31/08	13.38	03/31/08	13.38	03/31/08	32.36
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	4.70	09/30/08	0.87	09/30/08	47.46
06/30/08	4.92	06/30/08	0.90	06/30/08	48.35
03/31/08	5.18	03/31/08	0.75	03/31/08	43.97

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EXELON CORP (NYSE)				Scottrade
EXC 49.62	▾-1.50	(-2.93%)	Vol. 1,787,884	13:26 ET

Exelon Corporation is a utility holding company. Its subsidiaries are engaged principally in the production, purchase, transmission, distribution and sale of electricity to residential, commercial, industrial and wholesale customers and the distribution and sale of natural gas to residential, commercial and industrial customers. Exelon is a bold, creative, accountable and committed company, with employees dedicated in their efforts to set the standards for the utility services industry.

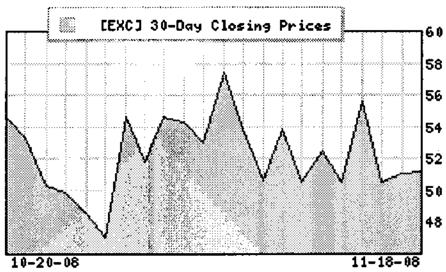
General Information

EXELON CORP
10 South Dearborn Street
37th Floor P.O. Box 805379
Chicago, IL 60680-5379
Phone: 312 394-7398
Fax: 312-394-7945
Web: www.extendicare.com
Email: cbarnes@extendicare.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	01/21/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	51.12
52 Week High	92.13
52 Week Low	41.23
Beta	0.81
20 Day Moving Average	5,575,981.00
Target Price Consensus	81.46



% Price Change		% Price Change Relative to S&P 500	
4 Week	-4.22	4 Week	6.48
12 Week	-32.80	12 Week	-0.54
YTD	-37.38	YTD	4.15

Share Information		Dividend Information	
Shares Outstanding (millions)	657.33	Dividend Yield	4.11%
		Annual Dividend	$2.10
Market Capitalization (millions)	33,602.81	Payout Ratio	0.48
Short Ratio	0.63	Change in Payout Ratio	0.00
Last Split Date	05/06/2004	Last Dividend Payout / Amount	11/12/2008 / $0.52

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.05	Current (1=Strong Buy, 5=Strong Sell)	1.70
Current Year EPS Consensus Estimate	4.19	30 Days Ago	1.64
Estimated Long-Term EPS Growth Rate	10.00	60 Days Ago	1.82
Next EPS Report Date	01/21/2009	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.20	vs. Previous Year	-11.57%	vs. Previous Year	3.90%
Trailing 12 Months:	12.32	vs. Previous Quarter	-5.31%	vs. Previous Quarter:	13.11%
PEG Ratio	1.22				

Price Ratios		ROE		ROA	
Price/Book	2.90	09/30/08	26.56	09/30/08	5.99
Price/Cash Flow	6.62	06/30/08	28.48	06/30/08	6.23
Price / Sales	1.78	03/31/08	27.16	03/31/08	6.18
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	1.02	09/30/08	0.82	09/30/08	14.55
06/30/08	0.84	06/30/08	0.73	06/30/08	15.32
03/31/08	0.85	03/31/08	0.73	03/31/08	15.17
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	20.90	09/30/08	20.90	09/30/08	17.63
06/30/08	22.15	06/30/08	22.15	06/30/08	15.07
03/31/08	21.48	03/31/08	21.48	03/31/08	14.77
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	9.39	09/30/08	1.06	09/30/08	51.63
06/30/08	9.87	06/30/08	1.28	06/30/08	56.11
03/31/08	10.42	03/31/08	1.30	03/31/08	56.72

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FIRSTENERGY CORP (NYSE)

Scottrade

FE	53.66	▼-0.34	(-0.63%)	Vol. 1,045,634	13:27 ET

FirstEnergy Corp. is a diversified energy services holding company as the result of the merger of Ohio Edison Company and Centerior Energy Corporation. FirstEnergy companies provide electricity and natural gas services and a wide array of energy-related products and services. FirstEnergy's four electric utility companies, Ohio Edison and its Pennsylvania Power subsidiary, The Illuminating Company and Toledo Edison, serve customers in northern and central Ohio and western Pennsylvania. (Company Press Release)

General Information

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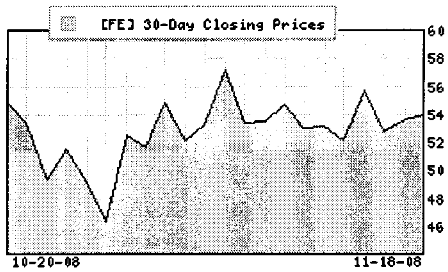
76 South Main Street
Akron, OH 44308
Phone: 800-736-3402
Fax: 330-384-3772
Web: www.firstenergycorp.com
Email: turoskyk@firstenergycorp.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/23/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	54.00
52 Week High	84.00
52 Week Low	41.20
Beta	0.77
20 Day Moving Average	2,601,786.00
Target Price Consensus	74.2



% Price Change

4 Week	1.31
12 Week	-26.43
YTD	-25.35

% Price Change Relative to S&P 500

4 Week	12.63
12 Week	8.88
YTD	22.61

Share Information

Shares Outstanding (millions)	304.83
Market Capitalization (millions)	16,461.09
Short Ratio	0.92
Last Split Date	N/A

Dividend Information

Dividend Yield	4.07%
Annual Dividend	$2.20
Payout Ratio	0.52
Change in Payout Ratio	-0.01
Last Dividend Payout / Amount	11/05/2008 / $0.55

EPS Information

Current Quarter EPS Consensus Estimate	1.05
Current Year EPS Consensus Estimate	4.34
Estimated Long-Term EPS Growth Rate	11.00
Next EPS Report Date	02/23/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	1.80
30 Days Ago	1.80
60 Days Ago	1.80
90 Days Ago	1.80

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.45	vs. Previous Year	18.66%	vs. Previous Year	8.44%
Trailing 12 Months:	12.77	vs. Previous Quarter	87.06%	vs. Previous Quarter:	22.00%
PEG Ratio	1.13				

Price Ratios **ROE** **ROA**

Price/Book	1.77	09/30/08	14.24	09/30/08	3.95
Price/Cash Flow	5.38	06/30/08	13.64	06/30/08	3.78
Price / Sales	1.22	03/31/08	14.78	03/31/08	4.08
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.40	09/30/08	0.31	09/30/08	9.64
06/30/08	0.40	06/30/08	0.32	06/30/08	9.30
03/31/08	0.38	03/31/08	0.29	03/31/08	9.99
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	15.21	09/30/08	15.21	09/30/08	30.51
06/30/08	15.39	06/30/08	15.39	06/30/08	30.25
03/31/08	16.55	03/31/08	16.55	03/31/08	29.50
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	9.89	09/30/08	0.93	09/30/08	48.26
06/30/08	9.78	06/30/08	0.93	06/30/08	48.27
03/31/08	9.42	03/31/08	1.07	03/31/08	51.69

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HAWAIIAN ELEC INDUSTRIES (NYSE)				Scottrade
HE	26.56	▲0.01	(0.04%)	Vol. 420,849	13:49 ET

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

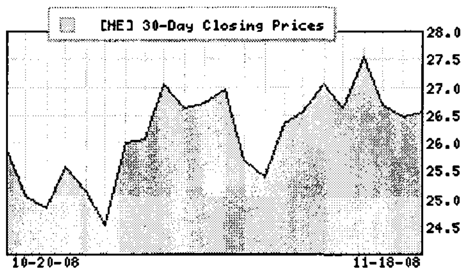
General Information

HAWAIIAN ELEC
900 Richards Street
Honolulu, HI 96813
Phone: 808 543-5662
Fax: 808 543-7966
Web: www.hei.com
Email: shollinger@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/12/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	26.55
52 Week High	29.75
52 Week Low	20.95
Beta	0.35
20 Day Moving Average	628,973.13
Target Price Consensus	25



% Price Change		% Price Change Relative to S&P 500	
4 Week	5.95	4 Week	17.78
12 Week	2.19	12 Week	51.25
YTD	16.60	YTD	97.01

Share Information		Dividend Information	
Shares Outstanding (millions)	84.72	Dividend Yield	4.67%
		Annual Dividend	$1.24
Market Capitalization (millions)	2,249.45	Payout Ratio	0.68
Short Ratio	7.74	Change in Payout Ratio	-0.18
Last Split Date	06/14/2004	Last Dividend Payout / Amount	11/13/2008 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.41	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.70	30 Days Ago	3.75
Estimated Long-Term EPS Growth Rate	4.20	60 Days Ago	3.25
Next EPS Report Date	02/12/2009	90 Days Ago	2.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.62	vs. Previous Year	29.41%	vs. Previous Year	35.93%
Trailing 12 Months:	14.59	vs. Previous Quarter	-8.33%	vs. Previous Quarter:	18.26%
PEG Ratio	3.75				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.70	09/30/08	11.74	09/30/08	2.00

Price/Cash Flow	25.74	06/30/08	11.46	06/30/08	1.83
Price / Sales	0.72	03/31/08	9.99	03/31/08	1.50
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.49	09/30/08	0.49	09/30/08	4.88
06/30/08	0.44	06/30/08	0.44	06/30/08	4.97
03/31/08	0.23	03/31/08	0.23	03/31/08	4.44
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	3.86	09/30/08	3.86	09/30/08	15.59
06/30/08	3.22	06/30/08	3.22	06/30/08	15.42
03/31/08	4.21	03/31/08	4.21	03/31/08	15.60
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	-	09/30/08	0.92	09/30/08	48.53
06/30/08	-	06/30/08	0.93	06/30/08	48.90
03/31/08	-	03/31/08	0.92	03/31/08	48.67

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MDU RES GROUP INC (NYSE)				Scottrade	
MDU	18.06	-0.65	(-3.47%)	Vol. 872,456	13:49 ET

MDU RESOURCES GROUP, INC. is a diversified natural resource company.Montana-Dakota Utilities Co., the public utility division of the Company, provides electric and/or natural gas and propane distribution service at retail to 256 communities in North Dakota, eastern Montana, northern and western South Dakota and northern Wyoming, and owns and operates electric power generation and transmission facilities.

General Information

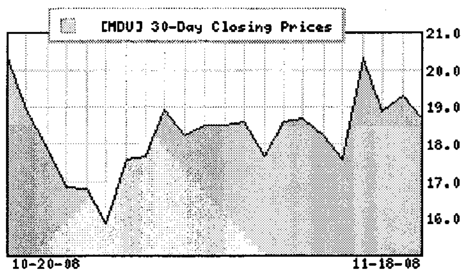
MDU RESOURCES
1200 West Century Avenue
P.O. Box 5650
Bismarck, ND 58506-5650
Phone: 701 530-1000
Fax: 701 222-7607
Web: www.mdu.com
Email: investor@mduresources.com

Industry	BLDG&CONST-MISC
Sector:	Construction

Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	01/16/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	18.71
52 Week High	35.34
52 Week Low	15.86
Beta	1.38
20 Day Moving Average	1,788,872.63
Target Price Consensus	29.5



% Price Change

4 Week	-1.21
12 Week	-41.64
YTD	-32.24

% Price Change Relative to S&P 500

4 Week	9.82
12 Week	-13.63
YTD	14.92

Share Information

Shares Outstanding (millions)	183.22
Market Capitalization (millions)	3,427.99
Short Ratio	0.95
Last Split Date	07/27/2006

Dividend Information

Dividend Yield	3.31%
Annual Dividend	$0.62
Payout Ratio	0.28
Change in Payout Ratio	-0.06
Last Dividend Payout / Amount	09/09/2008 / $0.16

EPS Information

Current Quarter EPS Consensus Estimate	0.43
Current Year EPS Consensus Estimate	2.05
Estimated Long-Term EPS Growth Rate	10.60
Next EPS Report Date	01/16/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	1.71
30 Days Ago	1.71
60 Days Ago	1.57
90 Days Ago	1.63

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	9.12	vs. Previous Year	12.28%	vs. Previous Year	7.11%
Trailing 12 Months:	8.58	vs. Previous Quarter	1.59%	vs. Previous Quarter:	6.55%
PEG Ratio	0.86				

Price Ratios		**ROE**		**ROA**	
Price/Book	1.24	09/30/08	15.39	09/30/08	6.69
Price/Cash Flow	5.46	06/30/08	15.33	06/30/08	6.67
Price / Sales	0.69	03/31/08	14.46	03/31/08	6.40
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	1.48	09/30/08	1.17	09/30/08	8.09
06/30/08	1.37	06/30/08	1.10	06/30/08	7.95
03/31/08	1.25	03/31/08	1.00	03/31/08	7.69
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	12.58	09/30/08	12.58	09/30/08	15.14
06/30/08	12.60	06/30/08	12.60	06/30/08	14.08
03/31/08	12.22	03/31/08	12.22	03/31/08	13.82
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	14.82	09/30/08	0.51	09/30/08	33.71
06/30/08	14.97	06/30/08	0.57	06/30/08	36.28
03/31/08	14.94	03/31/08	0.50	03/31/08	33.32

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OTTER TAIL CORP (NASD)

Scottrade

OTTR	16.36	▾-0.51	(-3.02%)	Vol. 180,386	13:51 ET

OTTER TAIL's primary business is the production, transmission, distribution and sale of electric energy. The Company, through its subsidiaries, is also engaged in other businesses which are referred to as Health Services Operations and Diversified Operations.

General Information

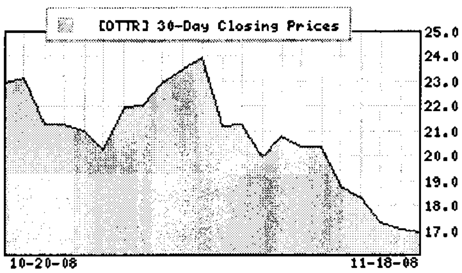
OTTER TAIL CORP
215 South Cascade Street
Box 496
Fergus Falls, - 56538-0496
Phone: 218-739-8479
Fax: 218-998-3165
Web: www.ottertail.com
Email: sharesvc@ottertail.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	16.87
52 Week High	46.15
52 Week Low	16.11
Beta	1.03
20 Day Moving Average	363,871.31
Target Price Consensus	29



% Price Change		% Price Change Relative to S&P 500	
4 Week	-27.10	4 Week	-18.95
12 Week	-56.71	12 Week	-35.93
YTD	-51.24	YTD	-15.83

Share Information		Dividend Information	
Shares Outstanding (millions)	34.63	Dividend Yield	7.05%
		Annual Dividend	$1.19
Market Capitalization (millions)	584.12	Payout Ratio	1.03
Short Ratio	2.63	Change in Payout Ratio	0.32
Last Split Date	03/16/2000	Last Dividend Payout / Amount	11/12/2008 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.42	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	1.13	30 Days Ago	2.67
Estimated Long-Term EPS Growth Rate	8.50	60 Days Ago	3.33
Next EPS Report Date	02/10/2009	90 Days Ago	4.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.00	vs. Previous Year	-29.55%	vs. Previous Year	16.95%
Trailing 12 Months:	14.67	vs. Previous Quarter	181.82%	vs. Previous Quarter:	9.23%
PEG Ratio	1.76				

Price Ratios		ROE		ROA	
Price/Book	0.86	09/30/08	6.32	09/30/08	2.33

Price/Cash Flow	4.72	06/30/08	7.52	06/30/08	2.69
Price / Sales	0.45	03/31/08	10.01	03/31/08	3.71
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	1.45	09/30/08	1.07	09/30/08	2.71
06/30/08	1.04	06/30/08	0.75	06/30/08	3.12
03/31/08	1.30	03/31/08	0.91	03/31/08	4.18
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	3.66	09/30/08	3.66	09/30/08	19.51
06/30/08	4.41	06/30/08	4.41	06/30/08	17.40
03/31/08	6.23	03/31/08	6.23	03/31/08	17.48
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	10.15	09/30/08	0.50	09/30/08	33.10
06/30/08	9.69	06/30/08	0.65	06/30/08	38.90
03/31/08	9.65	03/31/08	0.66	03/31/08	38.89

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PG&E CORP (NYSE)				Scottrade	
PCG	37.20	▲0.16	(0.43%)	Vol. 2,425,035	13:52 ET

PG&E Corporation is an energy-based holding company. Pacific Gas and Electric Company, the company's primary subsidiary, is an operating public utility engaged principally in the business of providing electricity and natural gas distribution and transmission services throughout most of Northern and Central California.

General Information

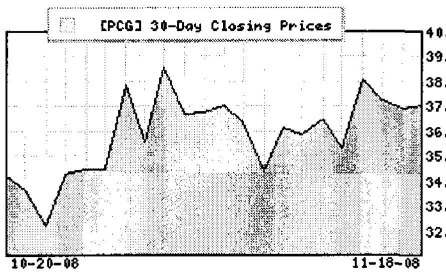
PG&E CORP
One Market Spear Tower
Suite 2400
San Francisco, CA 94105-1126
Phone: 415-267-7070
Fax: 415-267-7268
Web: www.pgecorp.com
Email: invrel@pge-corp.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/13/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	37.04
52 Week High	47.61
52 Week Low	26.67
Beta	0.60
20 Day Moving Average	3,423,307.50
Target Price Consensus	41.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	10.17	4 Week	22.47
12 Week	-9.46	12 Week	34.00
YTD	-14.04	YTD	45.20

Share Information		Dividend Information	
Shares Outstanding (millions)	358.56	Dividend Yield	4.21%
		Annual Dividend	$1.56
Market Capitalization (millions)	13,280.92	Payout Ratio	0.56
Short Ratio	1.89	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	09/26/2008 / $0.39

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.68	Current (1=Strong Buy, 5=Strong Sell)	2.15
Current Year EPS Consensus Estimate	2.94	30 Days Ago	2.15
Estimated Long-Term EPS Growth Rate	7.70	60 Days Ago	2.15
Next EPS Report Date	02/13/2009	90 Days Ago	2.08

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.61	vs. Previous Year	7.79%	vs. Previous Year	12.05%
Trailing 12 Months:	13.18	vs. Previous Quarter	3.75%	vs. Previous Quarter:	2.68%
PEG Ratio	1.64				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.45	09/30/08	11.61	09/30/08	2.70

Price/Cash Flow	4.52	06/30/08	11.56	06/30/08	2.68
Price / Sales	0.92	03/31/08	11.51	03/31/08	2.68
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.74	09/30/08	0.68	09/30/08	7.11
06/30/08	0.79	06/30/08	0.73	06/30/08	7.13
03/31/08	0.75	03/31/08	0.72	03/31/08	7.15
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	10.68	09/30/08	10.68	09/30/08	25.49
06/30/08	10.71	06/30/08	10.71	06/30/08	24.90
03/31/08	10.90	03/31/08	10.90	03/31/08	24.44
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	16.47	09/30/08	1.00	09/30/08	50.65
06/30/08	16.43	06/30/08	1.03	06/30/08	51.33
03/31/08	16.46	03/31/08	1.06	03/31/08	52.13

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PINNACLE WEST CAP CORP (NYSE)

Scottrade

PNW	28.82	▾-0.16	(-0.55%)	Vol. 634,836	13:53 ET

Pinnacle West Capital is engaged, through its subsidiaries, in the generation, transmission, and distribution of electricity and selling energy, products and services; in real estate development; and in venture capital investment. Its primary subsidiary is Arizona Public Service Company. The company's other subsidiaries include SunCor, El Dorado, APSEnergy Services and Pinnacle West Energy.

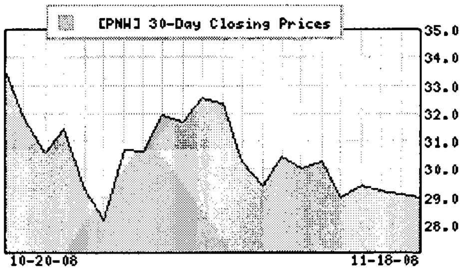
General Information

PINNACLE WEST
400 North Fifth Street
P.O. Box 53999
Phoenix, AZ 85072-3999
Phone: 602-250-1000
Fax: 602-250-2430
Web: www.pinnaclewest.com
Email: elisa.malagon@pinnaclewest.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	01/28/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	28.98
52 Week High	44.50
52 Week Low	26.27
Beta	0.55
20 Day Moving Average	1,361,472.88
Target Price Consensus	33.39



% Price Change

4 Week	-8.93
12 Week	-17.30
YTD	-31.67

% Price Change Relative to S&P 500

4 Week	1.24
12 Week	22.41
YTD	15.89

Share Information

Shares Outstanding (millions)	100.73
Market Capitalization (millions)	2,919.27
Short Ratio	3.88
Last Split Date	N/A

Dividend Information

Dividend Yield	7.25%
Annual Dividend	$2.10
Payout Ratio	0.91
Change in Payout Ratio	0.19
Last Dividend Payout / Amount	10/30/2008 / $0.52

EPS Information

Current Quarter EPS Consensus Estimate	0.01
Current Year EPS Consensus Estimate	2.46
Estimated Long-Term EPS Growth Rate	6.30
Next EPS Report Date	01/28/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	3.29
30 Days Ago	3.29
60 Days Ago	3.29
90 Days Ago	3.25

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.76	vs. Previous Year	-21.16%	vs. Previous Year	-10.44%
Trailing 12 Months:	12.55	vs. Previous Quarter	77.38%	vs. Previous Quarter:	16.60%
PEG Ratio	1.86				

Price Ratios	ROE	ROA

Price/Book	0.81	09/30/08	6.48	09/30/08	2.06
Price/Cash Flow	4.14	06/30/08	7.62	06/30/08	2.42
Price / Sales	0.83	03/31/08	7.63	03/31/08	2.38
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.73	09/30/08	0.53	09/30/08	6.67
06/30/08	0.88	06/30/08	0.65	06/30/08	7.56
03/31/08	0.67	03/31/08	0.46	03/31/08	7.53
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	10.47	09/30/08	10.47	09/30/08	35.87
06/30/08	11.93	06/30/08	11.93	06/30/08	37.24
03/31/08	11.78	03/31/08	11.78	03/31/08	35.27
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	5.23	09/30/08	0.84	09/30/08	45.75
06/30/08	5.75	06/30/08	0.82	06/30/08	45.16
03/31/08	6.11	03/31/08	0.88	03/31/08	46.77

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PNM RES INC (NYSE)					Scottrade
PNM	8.86	-0.47	(-5.04%)	Vol. 292,882	13:54 ET

PNM Resources is an energy holding company based in Albuquerque, New Mexico. Its principal subsidiary is Public Service Company of New Mexico, which provides electric power and natural gas utility services to more than 1.3 million people in New Mexico. The company also sells power on the wholesale market in the Western U.S.

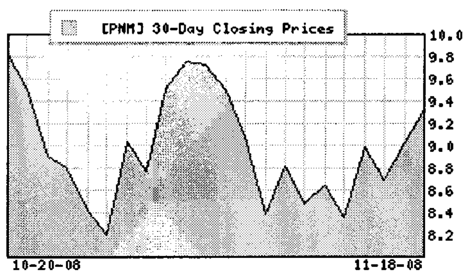
General Information

PNM RESOURCES
Alvarado Square
Albuquerque, NM 87158
Phone: 505 241-2700
Fax: 505 241-4311
Web: www.pnmresources.com
Email: Ethics@pnmresources.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/09/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	9.33
52 Week High	23.95
52 Week Low	7.64
Beta	1.07
20 Day Moving Average	878,284.38
Target Price Consensus	11.63



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	-1.89	4 Week	9.06
12 Week	-17.29	12 Week	22.42
YTD	-56.50	YTD	-31.88

Share Information		**Dividend Information**	
Shares Outstanding (millions)	86.40	Dividend Yield	5.36%
		Annual Dividend	$0.50
Market Capitalization (millions)	806.11	Payout Ratio	1.16
Short Ratio	4.52	Change in Payout Ratio	0.51
Last Split Date	06/14/2004	Last Dividend Payout / Amount	10/29/2008 / $0.26

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	-0.09	Current (1=Strong Buy, 5=Strong Sell)	3.14
Current Year EPS Consensus Estimate	0.16	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	3.00
Next EPS Report Date	02/09/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	59.55	vs. Previous Year	-34.15%	vs. Previous Year	-3.56%
Trailing 12 Months:	21.70	vs. Previous Quarter	-%	vs. Previous Quarter:	4.60%
PEG Ratio	9.93				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.47	09/30/08	2.14	09/30/08	0.60

Price/Cash Flow	2.72	06/30/08	2.59	06/30/08	0.73
Price / Sales	0.41	03/31/08	3.20	03/31/08	0.92
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.60	09/30/08	0.57	09/30/08	1.85
06/30/08	0.61	06/30/08	0.58	06/30/08	2.21
03/31/08	0.39	03/31/08	0.37	03/31/08	2.73
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	-14.24	09/30/08	-14.24	09/30/08	19.96
06/30/08	-13.15	06/30/08	-13.15	06/30/08	22.11
03/31/08	-4.96	03/31/08	-4.96	03/31/08	21.10
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	26.23	09/30/08	0.86	09/30/08	47.94
06/30/08	25.14	06/30/08	0.89	06/30/08	47.33
03/31/08	22.60	03/31/08	0.66	03/31/08	39.89

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PPL CORP (NYSE)					Scottrade
PPL	32.40	▾-0.27	(-0.83%)	Vol. 948,713	13:55 ET

PPL Corporation is an energy and utility holding company. PPL controls about 11,500 megawatts of generating capacity in the United States, sells energy in key U.S. markets and delivers electricity to customers in Pennsylvania, the United Kingdom and Latin America.

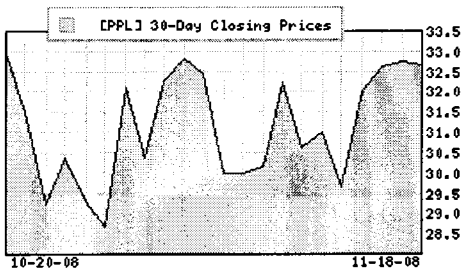
General Information

PPL CORP
Two North Ninth Street
Allentown, PA 18101-1179
Phone: 610-774-5151
Fax: 610-774-5106
Web: www.pplresources.com
Email: invrel@pplweb.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	01/22/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.67
52 Week High	55.23
52 Week Low	26.84
Beta	0.71
20 Day Moving Average	3,688,580.75
Target Price Consensus	47.78



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.62	4 Week	15.19
12 Week	-26.63	12 Week	8.58
YTD	-37.28	YTD	5.29

Share Information		Dividend Information	
Shares Outstanding (millions)	374.49	Dividend Yield	4.10%
		Annual Dividend	$1.34
Market Capitalization (millions)	12,234.62	Payout Ratio	0.62
Short Ratio	1.69	Change in Payout Ratio	0.13
Last Split Date	08/25/2005	Last Dividend Payout / Amount	09/08/2008 / $0.34

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.48	Current (1=Strong Buy, 5=Strong Sell)	1.67
Current Year EPS Consensus Estimate	2.04	30 Days Ago	1.44
Estimated Long-Term EPS Growth Rate	16.30	60 Days Ago	1.56
Next EPS Report Date	01/22/2009	90 Days Ago	1.56

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.05	vs. Previous Year	-37.50%	vs. Previous Year	76.57%
Trailing 12 Months:	15.13	vs. Previous Quarter	-10.00%	vs. Previous Quarter:	204.00%
PEG Ratio	0.98				

Price Ratios		ROE		ROA	
Price/Book	2.19	09/30/08	15.00	09/30/08	3.85

Price/Cash Flow	6.43	06/30/08	17.21	06/30/08	4.36
Price / Sales	1.68	03/31/08	18.15	03/31/08	4.86
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.96	09/30/08	0.86	09/30/08	11.30
06/30/08	1.04	06/30/08	0.98	06/30/08	15.62
03/31/08	1.12	03/31/08	1.04	03/31/08	15.11
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	16.93	09/30/08	16.93	09/30/08	14.91
06/30/08	23.42	06/30/08	23.42	06/30/08	13.89
03/31/08	21.14	03/31/08	21.14	03/31/08	14.98
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	11.57	09/30/08	1.20	09/30/08	55.75
06/30/08	6.91	06/30/08	1.35	06/30/08	58.61
03/31/08	6.73	03/31/08	1.27	03/31/08	56.95

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PROGRESS ENERGY INC (NYSE) Scottrade

PGN	38.87	▲0.11	(0.28%)	Vol. 880,521	13:57 ET

CP & L Energy, Inc. is primarily engaged in the generation, transmission,distribution and sale of electricity in portions of North and South Carolina and Florida and the transmission, distribution and sale of natural gas in portions of North Carolina. The company provides these and other services through its business segments: electric, natural gas and other.

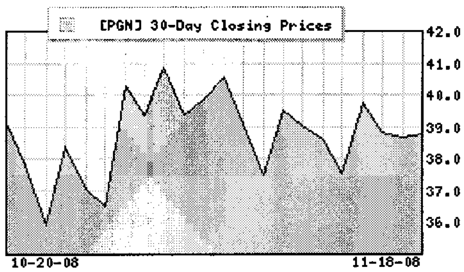
General Information

PROGRESS ENERGY
410 South Wilmington Street
Raleigh, NC 27601-1748
Phone: 919-546-6111
Fax: 919-546-7678
Web: www.progress-energy.com
Email: shareholder.relations@pgnmail.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/05/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	38.76
52 Week High	50.25
52 Week Low	32.60
Beta	0.52
20 Day Moving Average	2,094,853.25
Target Price Consensus	40.29



% Price Change

4 Week	2.49
12 Week	-12.51
YTD	-19.97

% Price Change Relative to S&P 500

4 Week	13.93
12 Week	29.49
YTD	34.85

Share Information

Shares Outstanding (millions)	261.99
Market Capitalization (millions)	10,154.62
Short Ratio	1.98
Last Split Date	02/01/1993

Dividend Information

Dividend Yield	6.35%
Annual Dividend	$2.46
Payout Ratio	0.85
Change in Payout Ratio	0.04
Last Dividend Payout / Amount	10/08/2008 / $0.62

EPS Information

Current Quarter EPS Consensus Estimate	0.51
Current Year EPS Consensus Estimate	3.02
Estimated Long-Term EPS Growth Rate	4.80
Next EPS Report Date	02/05/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.31
30 Days Ago	2.27
60 Days Ago	2.27
90 Days Ago	2.27

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.82	vs. Previous Year	-3.31%	vs. Previous Year	-13.03%
Trailing 12 Months:	13.37	vs. Previous Quarter	51.95%	vs. Previous Quarter:	20.14%
PEG Ratio	2.64				

Price Ratios		ROE		ROA	
Price/Book	1.15	09/30/08	8.70	09/30/08	2.71

Price/Cash Flow	5.84	06/30/08	8.93	06/30/08	2.79
Price / Sales	1.10	03/31/08	8.45	03/31/08	2.71
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	1.03	09/30/08	0.66	09/30/08	8.12
06/30/08	1.16	06/30/08	0.87	06/30/08	7.89
03/31/08	0.77	03/31/08	0.47	03/31/08	7.27
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	12.92	09/30/08	12.92	09/30/08	33.69
06/30/08	12.67	06/30/08	12.67	06/30/08	32.94
03/31/08	10.54	03/31/08	10.54	03/31/08	32.75
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	3.10	09/30/08	1.18	09/30/08	54.30
06/30/08	3.50	06/30/08	1.21	06/30/08	54.94
03/31/08	3.88	03/31/08	1.04	03/31/08	51.38

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SEMPRA ENERGY (NYSE)

Scottrade

SRE	41.20	-0.30	(-0.72%)	Vol. 809,260	13:58 ET

Sempra Energy is an energy services holding company. Through its eight principal subsidiaries -- Southern California Gas Company, San Diego Gas & Electric, Sempra Energy Solutions, Sempra Energy Trading, Sempra Energy International, Sempra Energy Resources, Sempra Communications and Sempra Energy Financial -- Sempra Energy serves customers in the United States, Europe, Canada, Mexico, South America and Asia. (Company Press Release)

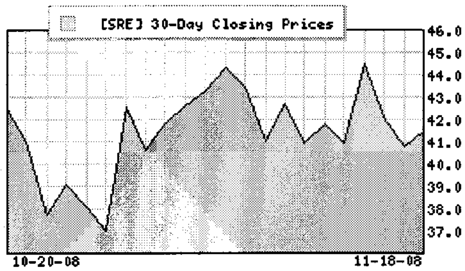
General Information

SEMPRA ENERGY
101 Ash Street
San Diego, CA 92101
Phone: 619-696-2034
Fax: 619-696-2374
Web: www.sempra.com
Email: investor@sempra.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/24/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	41.50
52 Week High	64.21
52 Week Low	34.29
Beta	0.93
20 Day Moving Average	2,247,892.50
Target Price Consensus	59.23



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.24	4 Week	12.55
12 Week	-27.61	12 Week	7.14
YTD	-32.94	YTD	14.37

Share Information		Dividend Information	
Shares Outstanding (millions)	246.38	Dividend Yield	3.37%
		Annual Dividend	$1.40
Market Capitalization (millions)	10,224.69	Payout Ratio	0.33
Short Ratio	0.84	Change in Payout Ratio	0.00
Last Split Date	06/29/1998	Last Dividend Payout / Amount	09/23/2008 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.87	Current (1=Strong Buy, 5=Strong Sell)	1.56
Current Year EPS Consensus Estimate	3.87	30 Days Ago	1.56
Estimated Long-Term EPS Growth Rate	7.00	60 Days Ago	1.38
Next EPS Report Date	02/24/2009	90 Days Ago	1.56

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.72	vs. Previous Year	-10.79%	vs. Previous Year	1.09%
Trailing 12 Months:	9.79	vs. Previous Quarter	26.53%	vs. Previous Quarter:	7.55%
PEG Ratio	1.53				

Price Ratios	ROE	ROA

Price/Book	1.35	09/30/08	13.20	09/30/08	3.88
Price/Cash Flow	5.99	06/30/08	13.98	06/30/08	4.04
Price / Sales	0.88	03/31/08	14.29	03/31/08	4.00
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	-	09/30/08	-	09/30/08	9.35
06/30/08	0.59	06/30/08	0.56	06/30/08	9.89
03/31/08	1.05	03/31/08	1.04	03/31/08	10.07
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	-	09/30/08	-	09/30/08	-
06/30/08	14.55	06/30/08	14.55	06/30/08	30.69
03/31/08	14.23	03/31/08	14.23	03/31/08	32.82
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	-	09/30/08	-	09/30/08	-
06/30/08	31.45	06/30/08	0.63	06/30/08	40.35
03/31/08	28.53	03/31/08	0.54	03/31/08	36.45

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WESTAR ENERGY INC (NYSE)

Scottrade

WR	19.43	▼-0.61	(-3.04%)	Vol. 969,603	13:59 ET

Westar Energy is a consumer services company with interests in monitored services and energy. Westar Energy provides electric utility services to customers in Kansas. Westar Energy's goal is to operate the best utility in the Midwest. They will provide their customers quality service at below average prices. Westar Energy Generation and Marketing will be a preferred energy provider, both inside and outside their service territory.

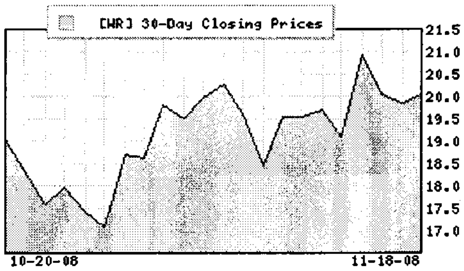
General Information

WESTAR ENERGY
-
-, - -
Phone: -
Fax: -
Web: -
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/20/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.04
52 Week High	26.83
52 Week Low	15.97
Beta	0.66
20 Day Moving Average	1,923,031.25
Target Price Consensus	24.19



% Price Change		% Price Change Relative to S&P 500	
4 Week	9.33	4 Week	21.54
12 Week	-11.84	12 Week	30.49
YTD	-22.75	YTD	29.83

Share Information		Dividend Information	
Shares Outstanding (millions)	108.15	Dividend Yield	5.79%
		Annual Dividend	$1.16
Market Capitalization (millions)	2,167.41	Payout Ratio	0.93
Short Ratio	3.05	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	09/05/2008 / $0.29

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.27	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	1.38	30 Days Ago	1.75
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	1.63
Next EPS Report Date	02/20/2009	90 Days Ago	1.63

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.52	vs. Previous Year	-18.18%	vs. Previous Year	4.81%
Trailing 12 Months:	16.03	vs. Previous Quarter	1,250.00%	vs. Previous Quarter:	27.40%
PEG Ratio	2.42				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.99	09/30/08	6.43	09/30/08	1.92

Price/Cash Flow	5.11	06/30/08	6.99	06/30/08	2.05
Price / Sales	1.19	03/31/08	8.96	03/31/08	2.58
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.72	09/30/08	0.52	09/30/08	7.10
06/30/08	1.04	06/30/08	0.81	06/30/08	7.39
03/31/08	0.83	03/31/08	0.60	03/31/08	9.07
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	10.81	09/30/08	10.81	09/30/08	20.27
06/30/08	11.06	06/30/08	11.06	06/30/08	20.33
03/31/08	13.21	03/31/08	13.21	03/31/08	19.59
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	3.38	09/30/08	0.92	09/30/08	47.64
06/30/08	3.27	06/30/08	1.01	06/30/08	50.05
03/31/08	3.12	03/31/08	1.05	03/31/08	50.90

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WISCONSIN ENERGY CORP (NYSE)					Scottrade
WEC	42.00	▼-0.31	(-0.73%)	Vol. 1,400,920	13:59 ET

Wisconsin Energy Corp. is a holding company with subsidiaries in utility and non-utility businesses. The company serves electric and natural gas customers in Wisconsin and Michigan's Upper Peninsula through its primary utility subsidiaries Wisconsin Electric, Wisconsin Gas and Edison Sault Electric. Its non-utility subsidiaries include energy services and development, pump manufacturing, waste-to-energy, and real estate businesses. (Company Press Release)

General Information

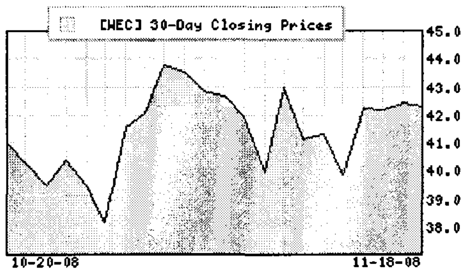
WISC ENERGY CP
231 West Michigan Street
P.O. Box 1331
Milwaukee, WI 53201
Phone: 414 221-2345
Fax: 414 221-2172
Web: www.wisconsinenergy.com
Email: WEC.Institutional-Investor-Relations.Contact@wisconsinenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	02/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	42.31
52 Week High	50.48
52 Week Low	34.89
Beta	0.49
20 Day Moving Average	2,533,096.75
Target Price Consensus	47.57



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	5.04	4 Week	16.77
12 Week	-8.50	12 Week	35.42
YTD	-13.14	YTD	45.57

Share Information		**Dividend Information**	
Shares Outstanding (millions)	116.92	Dividend Yield	2.55%
		Annual Dividend	$1.08
Market Capitalization (millions)	4,946.89	Payout Ratio	0.36
Short Ratio	2.74	Change in Payout Ratio	-0.01
Last Split Date	07/01/1992	Last Dividend Payout / Amount	11/12/2008 / $0.27

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.71	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	2.89	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	9.40	60 Days Ago	2.00
Next EPS Report Date	02/10/2009	90 Days Ago	1.86

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	14.65	vs. Previous Year	-7.14%	vs. Previous Year	-3.29%
Trailing 12 Months:	14.20	vs. Previous Quarter	32.65%	vs. Previous Quarter:	-9.89%
PEG Ratio	1.55				

Price Ratios		**ROE**		**ROA**	
Price/Book	1.51	09/30/08	11.06	09/30/08	3.01
Price/Cash Flow	7.34	06/30/08	11.45	06/30/08	3.06
Price / Sales	1.13	03/31/08	11.66	03/31/08	3.08
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	0.61	09/30/08	0.45	09/30/08	8.06
06/30/08	0.65	06/30/08	0.53	06/30/08	8.15
03/31/08	0.63	03/31/08	0.54	03/31/08	8.21
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	13.08	09/30/08	13.08	09/30/08	27.93
06/30/08	13.32	06/30/08	13.32	06/30/08	27.52
03/31/08	13.46	03/31/08	13.46	03/31/08	27.29
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	7.92	09/30/08	1.00	09/30/08	50.28
06/30/08	7.27	06/30/08	0.97	06/30/08	49.52
03/31/08	6.70	03/31/08	0.93	03/31/08	48.00

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XCEL ENERGY INC (NYSE)					Scottrade
XEL	17.93	▾-0.02	(-0.11%)	Vol. 2,114,424	14:00 ET

Xcel Energy Inc. is predominantly an operating public utility engaged in the generation, transmission and distribution of electricity and the transportation, storage and distribution of natural gas. The company has two significant subsidiaries, Northern States Power Company, a Wisconsin corporation, and NRG Energy, Inc.

General Information

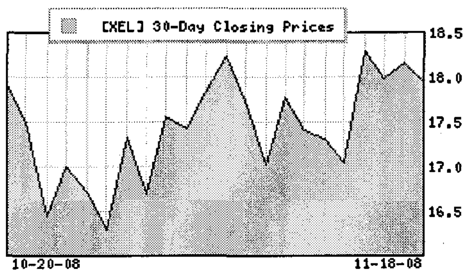
XCEL ENERGY INC
414 Nicollet Mall
Minneapolis, MN 55401
Phone: 612 215-4535
Fax: 612 330-2900
Web: www.xcelenergy.com
Email: Paul.A.Johnson@xcelenergy.com

Industry	UTIL-ELEC PWR
Sector:	*Utilities*

Fiscal Year End	December
Last Reported Quarter	09/30/08
Next EPS Date	01/28/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	17.95
52 Week High	23.50
52 Week Low	15.32
Beta	0.67
20 Day Moving Average	3,855,774.00
Target Price Consensus	20.6



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.57	4 Week	14.02
12 Week	-12.35	12 Week	29.72
YTD	-20.47	YTD	33.95

Share Information		Dividend Information	
Shares Outstanding (millions)	446.34	Dividend Yield	5.29%
		Annual Dividend	$0.95
Market Capitalization (millions)	8,011.77	Payout Ratio	0.68
Short Ratio	2.58	Change in Payout Ratio	0.03
Last Split Date	06/02/1998	Last Dividend Payout / Amount	09/23/2008 / $0.24

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.35	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	1.46	30 Days Ago	2.25
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.50
Next EPS Report Date	01/28/2009	90 Days Ago	2.43

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.32	vs. Previous Year	-8.93%	vs. Previous Year	18.14%
Trailing 12 Months:	12.82	vs. Previous Quarter	112.50%	vs. Previous Quarter:	8.41%
PEG Ratio	2.05				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.17	09/30/08	9.47	09/30/08	2.59

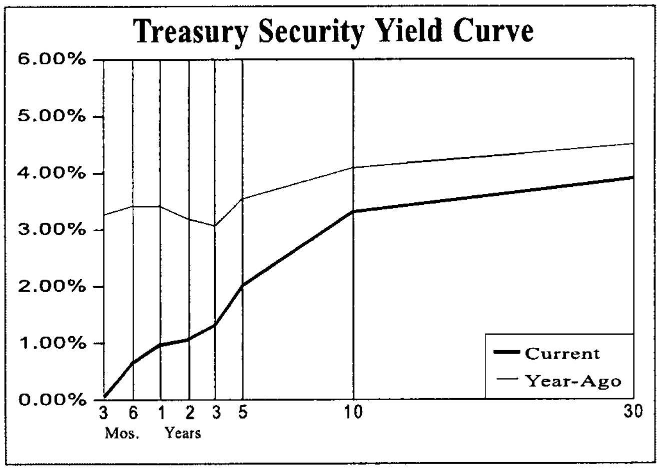
Price/Cash Flow	4.96	06/30/08	10.11	06/30/08	2.74
Price / Sales	0.72	03/31/08	10.56	03/31/08	2.86
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/08	1.00	09/30/08	0.76	09/30/08	5.53
06/30/08	0.84	06/30/08	0.68	06/30/08	5.98
03/31/08	0.92	03/31/08	0.77	03/31/08	6.36
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/08	7.86	09/30/08	7.86	09/30/08	15.34
06/30/08	8.53	06/30/08	8.53	06/30/08	14.80
03/31/08	9.07	03/31/08	9.07	03/31/08	14.81
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
09/30/08	12.27	09/30/08	1.09	09/30/08	51.84
06/30/08	12.20	06/30/08	1.12	06/30/08	52.42
03/31/08	12.11	03/31/08	1.12	03/31/08	52.49

ATTACHMENT C

Selected Yields

	Recent (11/19/08)	3 Months Ago (8/20/08)	Year Ago (11/20/07)
TAXABLE			
Market Rates			
Discount Rate	1.25	2.25	5.00
Federal Funds	1.00	2.00	4.50
Prime Rate	4.00	5.00	7.50
30-day CP (A1/P1)	2.60	2.77	4.59
3-month LIBOR	2.17	2.81	5.00
Bank CDs			
6-month	1.59	1.63	2.83
1-year	1.95	2.26	3.54
5-year	3.32	4.16	3.89
U.S. Treasury Securities			
3-month	0.06	1.68	3.28
6-month	0.65	1.90	3.42
1-year	0.97	2.04	3.43
5-year	2.02	3.01	3.55
10-year	3.32	3.80	4.10
10-year (inflation-protected)	3.51	1.54	1.70
30-year	3.91	4.45	4.50
30-year Zero	3.92	4.51	4.53

	Recent (11/19/08)	3 Months Ago (8/20/08)	Year Ago (11/20/07)
Mortgage-Backed Securities			
GNMA 6.5%	5.82	5.63	5.50
FHLMC 6.5% (Gold)	5.73	5.69	5.77
FNMA 6.5%	5.67	5.58	5.56
FNMA ARM	3.90	4.02	5.88
Corporate Bonds			
Financial (10-year) A	8.73	6.46	6.01
Industrial (25/30-year) A	7.23	6.22	5.96
Utility (25/30-year) A	7.34	6.17	6.04
Utility (25/30-year) Baa/BBB	8.20	6.65	6.14
Foreign Bonds (10-Year)			
Canada	3.51	3.58	4.07
Germany	3.54	4.12	4.06
Japan	1.48	1.45	1.47
United Kingdom	4.04	4.56	4.62
Preferred Stocks			
Utility A	7.10	6.18	6.62
Financial A	7.94	7.26	7.97
Financial Adjustable A	5.52	5.52	5.52



	Recent (11/19/08)	3 Months Ago (8/20/08)	Year Ago (11/20/07)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.14	4.67	4.53
25-Bond Index (Revs)	5.98	5.17	4.85
General Obligation Bonds (GOs)			
1-year Aaa	1.10	1.56	3.30
1-year A	1.20	1.66	3.34
5-year Aaa	2.84	2.80	3.34
5-year A	2.94	2.90	3.64
10-year Aaa	3.83	3.58	3.71
10-year A	4.03	3.78	4.00
25/30-year Aaa	5.20	4.66	4.47
25/30-year A	5.60	5.04	4.62
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.85	4.80	4.67
Electric AA	5.90	4.75	4.67
Housing AA	6.00	5.10	4.90
Hospital AA	6.10	5.20	4.85
Toll Road Aaa	5.95	4.75	4.67

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	11/5/08	10/22/08	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	363628	281707	81921	122327	62237	33210
Borrowed Reserves	675272	691147	-15875	383219	272426	167431
Net Free/Borrowed Reserves	-311644	-409440	97796	-260892	-210189	-134221

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	11/3/08	10/27/08	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1531.7	1487.7	44.0	34.0%	23.9%	11.4%
M2 (M1+savings+small time deposits)	7877.7	7877.5	0.2	11.0%	7.1%	7.2%

ATTACHMENT D

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity Dates (a)	Interest Rates	December 31, 2007	December 31, 2006
APS				
Pollution control bonds	2024-2034	(b)	$ 565,855	$ 565,855
Pollution control bonds with senior notes	2029	5.05%	90,000	90,000
Unsecured notes	2011	6.375%	400,000	400,000
Unsecured notes	2012	6.50%	375,000	375,000
Unsecured notes	2033	5.625%	200,000	200,000
Unsecured notes	2015	4.650%	300,000	300,000
Unsecured notes	2014	5.80%	300,000	300,000
Secured note	2014	6.00%	1,430	1,592
Senior notes	2035	5.50%	250,000	250,000
Senior notes (c)	2016	6.25%	250,000	250,000
Senior notes (c)	2036	6.875%	150,000	150,000
Unamortized discount and premium			(8,883)	(9,857)
Capitalized lease obligations	2007-2012	(d)	4,457	5,880
Subtotal (e)			2,877,859	2,878,470
SUNCOR				
Notes payable	2008-2013	(f)	237,671	180,316
Capitalized lease obligations	2007-2010	(g)	368	328
Subtotal			238,039	180,644
PINNACLE WEST				
Senior notes (h)	2011	5.91%	175,000	175,000
Capitalized lease obligations	2007	5.45%	—	115
Subtotal			175,000	175,115
Total long-term debt			3,290,898	3,234,229
Less current maturities			163,773	1,596
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 3,127,125	$ 3,232,633

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.

(b) The weighted-average rate was 3.76% at December 31, 2007 and 3.77% at December 31, 2006. Changes in short-term interest rates would affect the costs associated with this debt. In addition, these amounts include $343 million of auction rate debt securities backed by insurance at December 31, 2007 and 2006.

(c) On August 3, 2006, APS issued $250 million 6.25% notes due 2016 and $150 million 6.875% notes due 2036. A portion of the proceeds was used to repay outstanding commercial paper balances and $84 million of its 6.75% senior note that matured November 15, 2006. The remainder has been used to fund its construction program and other general corporate purposes.

(d) The weighted-average interest rate was 5.51% at December 31, 2007 and 6.20% at December 31, 2006.

(e) APS' long-term debt less current maturities was $2.877 billion at December 31, 2007 and $2.878 billion at December 31, 2006. APS' current maturities of long-term debt were $1 million at December 31, 2007 and 2006.

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172
TABLE OF CONTENTS TO SCHEDULES WAR

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
COST OF CAPITAL SUMMARY

WEIGHTED COST OF CAPITAL

		(A)	(B)	(C)	(D)	(E)	(F)
LINE NO.	DESCRIPTION	COPANY PROPOSED	RUCO ADJUSTMENT	RUCO ADJUSTED	CAPITAL RATIO	COST	WEIGHTED COST
1	LONG-TERM DEBT	$ 2,886,741	$ -	$ 2,886,741	46.21%	5.48%	2.53%
2	COMMON EQUITY	3,360,185	-	3,360,185	53.79%	9.60%	5.16%
3	TOTAL CAPITALIZATION	$ 6,246,926	$ -	$ 6,246,926	100.00%		
4	**WEIGHTED AVERAGE COST OF CAPITAL**						**7.70%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) - COLUMN (B)
COLUMN (D): LINE 1 AND 2 ÷ LINE 3
COLUMN (E): LINE 1 - SCHEDULE WAR-1, PAGE 2, LINE 16
LINE 2 - SCHEDULE WAR-1, PAGE 3, LINE 7
COLUMN (F): COLUMN (D) x COLUMN (E)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
COST OF CAPITAL SUMMARY

WEIGHTED COST OF DEBT

LINE NO.	DESCRIPTION	(A) MATURITY DATES	(B) BALANCE AS OF DECEMBER 31, 2008	(C) RUCO ADJUSTMENT	(D) RUCO ADJUSTED BALANCE	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	POLLUTION CONTROL BONDS	2024-2034	$ 565,855	$ -	$ 565,855	19.60%	3.760%	0.74%
2	POLLUTION CONTROL BONDS WITH SENIOR NOTES	2029	90,000	-	90,000	3.12%	5.050%	0.16%
3	UNSECURED NOTES	2011	400,000	-	400,000	13.86%	6.375%	0.88%
4	UNSECURED NOTES	2012	375,000	-	375,000	12.99%	6.500%	0.84%
5	UNSECURED NOTES	2033	200,000	-	200,000	6.93%	5.625%	0.39%
6	UNSECURED NOTES	2015	300,000	-	300,000	10.39%	4.650%	0.48%
7	UNSECURED NOTES	2014	300,000	-	300,000	10.39%	5.800%	0.60%
8	SECURED NOTE	2014	1,430	-	1,430	0.05%	6.000%	0.00%
9	SENIOR NOTES	2035	250,000	-	250,000	8.66%	5.500%	0.48%
10	SENIOR NOTES	2016	250,000	-	250,000	8.66%	6.250%	0.54%
11	SENIOR NOTES	2036	150,000	-	150,000	5.20%	6.875%	0.36%
12	CAPITALIZED LEASE OBLIGATIONS	2007-2012	4,457	-	4,457	0.15%	5.510%	0.01%
13								
14	TOTALS		$ 2,886,741	$ -	$ 2,886,741	100.00%		
15								
16	**WEIGHTED AVERAGE COST OF DEBT**							5.48%

REFERENCES:
COLUMNS (A) AND (B): COMPANY FORM 10-K FILED ON 02/27/2008, PAGE 107 0F236, SCHEDULE E-9
COLUMN (C): TESTIMONY WAR
COLUMN (D): COLUMN (B) - COLUMN (C)
COLUMN (E): LINES 1 THROUGH 12 ÷ LINE 14
COLUMN (F): COMPANY FORM 10-K FILED ON 02/27/2008, PAGE 107 0F236, SCHEDULE E-9
COLUMN (G): COLUMN (E) x COLUMN (F)

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	12.26%	SCHEDULE WAR-2, COLUMN (C), LINE 21
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	6.24%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 18
5	CAPM - ARITHMETIC MEAN ESTIMATE	7.64%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 18
6	AVERAGE OF CAPM ESTIMATES	6.94%	(LINE 4 + LINE 5) ÷ 2
7	**AVERAGE OF DCF AND CAPM RESULTS**	$\boxed{9.60\%}$	(LINE 2 + LINE 6) ÷ 2

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-01345A-08-0172
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) DIVIDEND YIELD		(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ALE	ALLETTE, INC.	4.65%	+	4.46%	=	9.11%
2	LNT	ALLIANT ENERGY	4.78%	+	5.07%	=	9.85%
3	AEE	AMEREN CORP.	7.80%	+	4.24%	=	12.04%
4	EXC	EXELON CORPORATION	3.95%	+	12.01%	=	15.96%
5	FE	FIRSTENERGY CORP.	4.08%	+	7.25%	=	11.33%
6	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	4.74%	+	3.98%	=	8.73%
7	MDU	MDU RESOURCES GROUP	2.91%	+	8.87%	=	11.78%
8	OTTR	OTTER TAIL CORPORATION	5.40%	+	1.78%	=	7.19%
9	PCG	PG&E CORPORATION	4.41%	+	5.68%	=	10.08%
10	PNW	PINNACLE WEST CAPITAL CORPORATION	6.77%	+	2.54%	=	9.31%
11	PNM	PNM RESOURCES	10.05%	+	19.27%	=	29.31%
12	PPL	PPL CORPORATION	4.19%	+	6.01%	=	10.19%
13	PGN	PROGRESSS ENERGY	6.26%	+	2.13%	=	8.40%
14	SRE	SEMPRA ENERGY	3.33%	+	8.50%	=	11.83%
15	WR	WESTAR ENERGY, INC.	5.92%	+	18.31%	=	24.23%
16	WEC	WISCONSIN ENERGY CORPORATION	2.60%	+	6.76%	=	9.36%
17	XEL	XCEL ENERGY INC.	5.36%	+	4.29%	=	9.65%
21	**AVERAGE**						**12.26%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01345A-08-0172
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ALE	ALLETTE, INC.	$ 1.72	÷	$ 36.96	=	4.65%
2	LNT	ALLIANT ENERGY	1.40	÷	29.28	=	4.78%
3	AEE	AMEREN CORP.	2.54	÷	32.57	=	7.80%
4	EXC	EXELON CORPORATION	2.10	÷	53.11	=	3.95%
5	FE	FIRSTENERGY CORP.	2.20	÷	53.98	=	4.08%
6	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.24	÷	26.13	=	4.74%
7	MDU	MDU RESOURCES GROUP	0.58	÷	19.93	=	2.91%
8	OTTR	OTTER TAIL CORPORATION	1.19	÷	22.06	=	5.40%
9	PCG	PG&E CORPORATION	1.56	÷	35.40	=	4.41%
10	PNW	PINNACLE WEST CAPITAL CORPORATION	2.10	÷	31.02	=	6.77%
11	PNM	PNM RESOURCES	0.92	÷	9.16	=	10.05%
12	PPL	PPL CORPORATION	1.34	÷	32.00	=	4.19%
13	PGN	PROGRESSS ENERGY	2.46	÷	39.28	=	6.26%
14	SRE	SEMPRA ENERGY	1.40	÷	42.05	=	3.33%
15	WR	WESTAR ENERGY, INC.	1.16	÷	19.61	=	5.92%
16	WEC	WISCONSIN ENERGY CORPORATION	1.08	÷	41.49	=	2.60%
17	XEL	XCEL ENERGY INC.	0.95	÷	17.78	=	5.36%
18	**AVERAGE**						**5.13%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ALE	ALLETTE, INC.	3.50%	+	0.96%	=	4.46%
2	LNT	ALLIANT ENERGY	5.00%	+	0.07%	=	5.07%
3	AEE	AMEREN CORP.	2.25%	+	1.99%	=	4.24%
4	EXC	EXELON CORPORATION	12.00%	+	0.01%	=	12.01%
5	FE	FIRSTENERGY CORP.	7.25%	+	0.00%	=	7.25%
6	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	3.25%	+	0.73%	=	3.98%
7	MDU	MDU RESOURCES GROUP	8.70%	+	0.17%	=	8.87%
8	OTTR	OTTER TAIL CORPORATION	1.75%	+	0.03%	=	1.78%
9	PCG	PG&E CORPORATION	5.50%	+	0.18%	=	5.68%
10	PNW	PINNACLE WEST CAPITAL CORPORATION	2.15%	+	0.39%	=	2.54%
11	PNM	PNM RESOURCES	1.50%	+	17.77%	=	19.27%
12	PPL	PPL CORPORATION	6.00%	+	0.01%	=	6.01%
13	PGN	PROGRESSS ENERGY	2.00%	+	0.13%	=	2.13%
14	SRE	SEMPRA ENERGY	8.50%	+	0.00%	=	8.50%
15	WR	WESTAR ENERGY, INC.	3.00%	+	15.31%	=	18.31%
16	WEC	WISCONSIN ENERGY CORPORATION	6.75%	+	0.01%	=	6.76%
17	XEL	XCEL ENERGY INC.	4.25%	+	0.04%	=	4.29%
18	**AVERAGE**						$\boxed{7.13\%}$

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01345A-08-0172
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) SHARE GROWTH	x { [((	(B) M ÷ B	) + 1) ÷ 2] - 1 } =	(C) EXTERNAL GROWTH (sv)
1	ALE	ALLETTE, INC.	4.25%	x { [((	1.45	) + 1) ÷ 2] - 1 } =	0.96%
2	LNT	ALLIANT ENERGY	1.00%	x { [((	1.14	) + 1) ÷ 2] - 1 } =	0.07%
3	AEE	AMEREN CORP.	1.00%	x { [((	0.98	) + 1) ÷ 2] + 1 } =	1.99%
4	EXC	EXELON CORPORATION	0.01%	x { [((	3.14	) + 1) ÷ 2] - 1 } =	0.01%
5	FE	FIRSTENERGY CORP.	0.01%	x { [((	1.72	) + 1) ÷ 2] - 1 } =	0.00%
6	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2.00%	x { [((	1.73	) + 1) ÷ 2] - 1 } =	0.73%
7	MDU	MDU RESOURCES GROUP	1.00%	x { [((	1.34	) + 1) ÷ 2] - 1 } =	0.17%
8	OTTR	OTTER TAIL CORPORATION	0.75%	x { [((	1.09	) + 1) ÷ 2] - 1 } =	0.03%
9	PCG	PG&E CORPORATION	0.75%	x { [((	1.47	) + 1) ÷ 2] - 1 } =	0.18%
10	PNW	PINNACLE WEST CAPITAL CORPORATION	0.20%	x { [((	0.87	) + 1) ÷ 2] + 1 } =	0.39%
11	PNM	PNM RESOURCES	10.25%	x { [((	0.47	) + 1) ÷ 2] + 1 } =	17.77%
12	PPL	PPL CORPORATION	0.01%	x { [((	2.03	) + 1) ÷ 2] - 1 } =	0.01%
13	PGN	PROGRESSS ENERGY	1.50%	x { [((	1.18	) + 1) ÷ 2] - 1 } =	0.13%
14	SRE	SEMPRA ENERGY	0.01%	x { [((	1.28	) + 1) ÷ 2] - 1 } =	0.00%
15	WR	WESTAR ENERGY, INC.	7.75%	x { [((	0.95	) + 1) ÷ 2] + 1 } =	15.31%
16	WEC	WISCONSIN ENERGY CORPORATION	0.05%	x { [((	1.48	) + 1) ÷ 2] - 1 } =	0.01%
17	XEL	XCEL ENERGY INC.	0.50%	x { [((	1.17	) + 1) ÷ 2] - 1 } =	0.04%
18	**AVERAGE**						**2.22%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 09/26/2008, 11/07/2008 AND 11/28/2008
COLUMN (C): COLUMN (A) x COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b) x	(B) RETURN ON BOOK EQUITY (r) =	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ALE	ALLETTE, INC.	2003	NMF	-	NMF	-	-	
2			2004	0.7778	6.10%	4.74%	21.23	29.70	
3			2005	0.4960	11.30%	5.60%	20.03	30.10	
4			2006	0.4765	11.60%	5.53%	21.90	30.40	
5			2007	0.4675	11.80%	5.52%	24.11	30.80	
6			GROWTH 2003 - 2007			5.35%	-		0.58%
7			2008	0.3965	10.00%	3.96%		32.30	4.87%
8			2009	0.3898	10.00%	3.90%		33.60	4.45%
9			2011-13	0.3846	9.50%	3.65%	6.50%	36.50	3.45%
10									
11	LNT	ALLIANT ENERGY	2003	0.3631	6.70%	2.43%	21.37	110.96	
12			2004	0.4486	8.20%	3.68%	22.13	115.74	
13			2005	0.5249	13.10%	6.88%	20.85	117.04	
14			2006	0.4417	9.10%	4.02%	22.83	116.13	
15			2007	0.5279	11.30%	5.97%	24.30	110.36	
16			GROWTH 2003 - 2007			5.13%	0.50%		-1.46%
17			2008	0.4909	11.50%	5.65%		111.00	0.58%
18			2009	0.4724	10.50%	4.96%		112.00	0.74%
19			2011-13	0.4182	10.00%	4.18%	6.00%	119.00	1.52%
20									
21	AEE	AMEREN CORP.	2003	0.1911	11.60%	2.22%	26.73	162.90	
22			2004	0.0993	9.10%	0.90%	29.71	195.20	
23			2005	0.1885	9.70%	1.83%	31.09	204.70	
24			2006	0.0451	8.10%	0.37%	31.86	206.60	
25			2007	0.2395	9.00%	2.16%	32.35	208.73	
26			GROWTH 2003 - 2007			1.49%	5.50%		6.39%
27			2008	0.1806	9.50%	1.72%		210.00	0.61%
28			2009	0.2185	9.50%	2.08%		212.00	0.78%
29			2011-13	0.2845	9.50%	2.70%	3.00%	222.00	1.24%
30									
31	EXC	EXELON CORPORATION	2003	0.6066	18.80%	11.40%	12.84	662.00	
32			2004	0.5418	19.50%	10.57%	14.19	664.20	
33			2005	0.5016	23.60%	11.84%	13.70	666.00	
34			2006	0.5314	23.70%	12.59%	14.89	670.00	
35			2007	0.5484	26.90%	14.75%	15.34	661.00	
36			GROWTH 2003 - 2007			12.14%	4.00%		-0.04%
37			2008	0.5133	26.00%	13.34%		650.00	-1.66%
38			2009	0.5385	25.50%	13.73%		645.00	-1.22%
39			2011-13	0.6000	25.00%	15.00%	9.00%	620.00	-1.27%

REFERENCES:
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COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2003 - 2007

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b) x	(B) RETURN ON BOOK EQUITY (r) =	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	FE	FIRSTENERGY CORP.	2003	-0.0204	5.40%	NMF	25.13	329.84	
2			2004	0.3105	10.60%	3.29%	26.04	329.84	
3			2005	0.3979	10.20%	4.06%	27.86	329.84	
4			2006	0.5157	13.90%	7.17%	28.30	319.21	
5			2007	0.5142	14.60%	7.51%	29.45	304.84	
6			GROWTH 2003 - 2007			5.51%	4.50%		-1.95%
7			2008	0.4767	13.50%	6.44%		304.85	0.00%
8			2009	0.5196	15.00%	7.79%		304.85	0.00%
9			2011-13	0.5481	15.50%	8.50%	7.50%	304.85	0.00%
10									
11	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2003	0.2152	10.80%	2.32%	14.36	75.84	
12			2004	0.0882	8.90%	0.79%	15.01	80.69	
13			2005	0.1507	9.70%	1.46%	15.02	80.98	
14			2006	0.0677	9.90%	0.67%	13.44	81.46	
15			2007	-0.1171	7.20%	NMF	15.29	83.43	
16			GROWTH 2003 - 2007			1.31%	2.00%		2.41%
17			2008	-0.1273	7.00%	NMF		85.50	2.48%
18			2009	0.2485	10.50%	2.61%		87.50	2.41%
19			2011-13	0.3500	11.50%	4.03%	2.50%	89.00	1.30%
20									
21	MDU	MDU RESOURCES GROUP	2003	0.5926	12.70%	7.53%	8.44	170.04	
22			2004	0.6083	12.70%	7.73%	9.39	177.34	
23			2005	0.6797	14.60%	9.92%	10.43	179.86	
24			2006	0.7029	14.80%	10.40%	11.88	181.02	
25			2007	0.6818	12.80%	8.73%	13.75	182.95	
26			GROWTH 2003 - 2007			8.23%	11.50%		1.85%
27			2008	0.7000	13.50%	9.45%		185.00	1.12%
28			2009	0.6878	12.50%	8.60%		187.00	1.10%
29			2011-13	0.6960	12.00%	8.35%	9.50%	193.00	1.08%
30									
31	OTTR	OTTER TAIL CORPORATION	2003	0.2848	11.70%	3.33%	12.98	25.72	
32			2004	0.2667	9.10%	2.43%	14.81	28.98	
33			2005	0.3708	11.20%	4.15%	15.80	29.40	
34			2006	0.3195	10.20%	3.26%	16.67	29.52	
35			2007	0.3427	10.20%	3.50%	17.55	29.85	
36			GROWTH 2003 - 2007			3.33%	7.50%		3.79%
37			2008	0.3389	10.00%	3.39%		31.00	3.85%
38			2009	0.3632	10.00%	3.63%		31.10	2.07%
39			2011-13	0.4356	10.00%	4.36%	4.50%	33.00	2.03%

REFERENCES:
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COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2003 - 2007

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COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	PCG	PG&E CORPORATION	2003	NMF		18.50%		NMF	10.12	416.52	
2			2004	NMF		10.30%		NMF	20.62	418.62	
3			2005	0.6170		12.30%		7.59%	19.60	368.27	
4			2006	0.5235		12.50%		6.54%	20.95	372.80	
5			2007	0.4928		11.70%		5.77%	22.60	378.39	
6			GROWTH 2003 - 2007					6.63%	16.50%		-2.37%
7			2008	0.4712		12.00%		5.65%		381.00	0.69%
8			2009	0.4750		12.50%		5.94%		384.00	0.74%
9			2011-13	0.4171		11.50%		4.80%	5.50%	393.00	0.76%
10											
11	PNW	PINNACLE WEST CAPITAL CORPORATION	2003	0.3135		8.10%		2.54%	31.00	91.29	
12			2004	0.2907		8.00%		2.33%	32.14	91.79	
13			2005	0.1384		6.50%		0.90%	34.57	99.08	
14			2006	0.3596		9.20%		3.31%	34.47	99.96	
15			2007	0.2905		8.50%		2.47%	35.15	100.49	
16			GROWTH 2003 - 2007					2.31%	3.50%		2.43%
17			2008	0.2500		8.00%		2.00%		100.70	0.21%
18			2009	0.2690		8.00%		2.15%		100.90	0.20%
19			2011-13	0.2698		8.00%		2.16%	2.00%	101.50	0.20%
20											
21	PNM	PNM RESOURCES	2003	0.4696		6.30%		2.96%	17.84	60.39	
22			2004	0.5594		8.00%		4.48%	18.19	60.46	
23			2005	0.5031		8.20%		4.13%	18.70	68.79	
24			2006	0.5000		7.20%		3.60%	22.09	76.65	
25			2007	-0.1974		3.50%		NMF	22.03	76.81	
26			GROWTH 2003 - 2007					3.79%	5.00%		6.20%
27			2008	-8.2000		0.50%		NMF		91.00	18.47%
28			2009	0.2333		6.00%		1.40%		91.00	8.85%
29			2011-13	0.2923		6.00%		1.75%	-	91.00	3.45%
30											
31	PPL	PPL CORPORATION	2003	0.5815		19.60%		11.40%	9.19	354.72	
32			2004	0.5615		16.30%		9.15%	11.21	378.14	
33			2005	0.5000		16.70%		8.35%	11.62	380.15	
34			2006	0.5197		17.30%		8.99%	13.30	385.04	
35			2007	0.5361		18.20%		9.76%	14.88	373.27	
36			GROWTH 2003 - 2007					9.53%	15.00%		1.28%
37			2008	0.4531		15.50%		7.02%		374.00	0.20%
38			2009	0.4275		16.00%		6.84%		368.00	-0.71%
39			2011-13	0.5200		22.00%		11.44%	10.00%	362.00	-0.61%

REFERENCES:
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COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b) x	(B) RETURN ON BOOK EQUITY (r) =	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	PGN	PROGRESSS ENERGY	2003	0.3372	10.90%	3.68%	30.26	246.00	
2			2004	0.2516	9.90%	2.49%	30.90	247.00	
3			2005	0.1905	9.00%	1.71%	31.90	252.00	
4			2006	-0.1805	6.10%	NMF	32.37	256.00	
5			2007	0.0929	8.20%	0.76%	32.38	260.10	
6			GROWTH 2003 - 2007			2.16%	3.00%		1.40%
7			2008	0.1767	9.00%	1.59%		264.00	1.50%
8			2009	0.1968	9.00%	1.77%		268.00	1.51%
9			2011-13	0.2500	9.50%	2.38%	1.50%	280.00	1.49%
10									
11	SRE	SEMPRA ENERGY	2003	0.6678	16.60%	11.09%	17.17	226.60	
12			2004	0.7455	18.90%	14.09%	20.78	234.18	
13			2005	0.6705	14.40%	9.65%	23.95	257.19	
14			2006	0.7163	14.80%	10.60%	28.66	262.01	
15			2007	0.7089	13.50%	9.57%	31.87	261.21	
16			GROWTH 2003 - 2007			11.00%	16.50%		3.62%
17			2008	0.6347	12.00%	7.62%		245.00	-6.21%
18			2009	0.6364	14.00%	8.91%		231.00	-5.96%
19			2011-13	0.6522	13.50%	8.80%	8.00%	240.00	-1.68%
20									
21	WR	WESTAR ENERGY, INC.	2003	0.4122	10.30%	4.25%	14.23	72.84	
22			2004	0.3162	7.10%	2.25%	16.13	86.03	
23			2005	0.4065	9.50%	3.86%	16.31	86.84	
24			2006	0.4787	10.70%	5.12%	17.62	87.39	
25			2007	0.4130	9.20%	3.80%	19.14	95.46	
26			GROWTH 2003 - 2007			3.85%	-4.50%		6.99%
27			2008	0.4200	9.50%	3.99%		102.00	6.85%
28			2009	0.2941	8.00%	2.35%		102.60	3.67%
29			2011-13	0.3231	8.50%	2.75%	4.50%	104.40	1.81%
30									
31	WEC	WISCONSIN ENERGY CORPORATION	2003	0.6460	11.40%	7.36%	19.92	118.43	
32			2004	0.5514	8.80%	4.85%	21.31	116.99	
33			2005	0.6563	11.30%	7.42%	22.91	116.98	
34			2006	0.6515	10.80%	7.04%	24.70	116.97	
35			2007	0.6479	10.90%	7.06%	26.50	116.94	
36			GROWTH 2003 - 2007			6.67%	7.00%		-0.32%
37			2008	0.6143	10.00%	6.14%		117.00	0.05%
38			2009	0.6185	11.00%	6.80%		117.00	0.03%
39			2011-13	0.6235	12.00%	7.48%	6.50%	117.00	0.01%

REFERENCES:
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COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	XEL	XCEL ENERGY INC.	2003	0.3902		9.80%		3.82%	12.95	398.96	
2			2004	0.3622		10.00%		3.62%	12.99	400.46	
3			2005	0.2917		9.20%		2.68%	13.37	403.39	
4			2006	0.3481		9.70%		3.38%	14.28	407.30	
5			2007	0.3259		9.10%		2.97%	14.70	428.78	
6			GROWTH 2003 - 2007					3.29%	-1.50%		1.82%
7			2008	0.3733		10.00%		3.73%		430.00	0.28%
8			2009	0.3742		10.00%		3.74%		432.00	0.37%
9			2011-13	0.4700		11.00%		5.17%	4.50%	438.00	0.43%

REFERENCES:
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DATED 09/26/2008, 11/07/2008 AND 11/28/2008
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINE 6, SIMPLE AVERAGE GROWTH, 2003 - 2007

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINE 6, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
GROWTH RATE COMPARISON

DOCKET NO. E-01345A-08-0172
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	ALE	ALLETTE, INC.	4.46%	5.00%	2.50%	5.50%	6.50%	-	-	-	4.88%	-	-	-
2	LNT	ALLIANT ENERGY	5.07%	6.10%	6.00%	9.00%	6.00%	-3.00%	-10.50%	0.50%	2.01%	14.41%	6.16%	3.26%
3	AEE	AMEREN CORP.	4.24%	5.00%	3.50%	-	3.00%	-0.50%	-	5.50%	3.30%	1.56%	0.00%	4.89%
4	EXC	EXELON CORPORATION	12.01%	10.00%	8.00%	6.50%	9.00%	12.50%	23.00%	4.00%	10.43%	13.36%	17.34%	4.55%
5	FE	FIRSTENERGY CORP.	7.25%	11.00%	11.00%	8.50%	7.00%	6.00%	4.50%	4.50%	7.50%	30.17%	8.12%	4.05%
6	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	3.98%	4.20%	7.50%	1.00%	2.50%	-3.00%	-	2.00%	2.37%	-8.45%	0.00%	1.58%
7	MDU	MDU RESOURCES GROUP	8.87%	10.60%	7.00%	6.50%	9.50%	14.00%	5.50%	11.50%	9.23%	12.99%	6.21%	12.98%
8	OTTR	OTTER TAIL CORPORATION	1.78%	8.50%	2.50%	1.50%	5.50%	0.50%	2.00%	7.50%	4.00%	4.20%	2.02%	7.83%
9	PCG	PG&E CORPORATION	5.68%	7.70%	5.00%	9.00%	5.50%	-	-	16.50%	8.74%	7.91%	-	22.25%
10	PNW	PINNACLE WEST CAPITAL CORPORATION	2.54%	6.30%	2.00%	2.00%	2.00%	-2.50%	5.50%	3.50%	2.69%	4.11%	4.96%	3.19%
11	PNM	PNM RESOURCES	19.27%	6.00%	-1.00%	1.50%	-	-5.00%	9.50%	5.00%	2.67%	-9.84%	10.52%	5.42%
12	PPL	PPL CORPORATION	6.01%	16.30%	12.00%	13.00%	8.50%	6.50%	13.00%	15.00%	12.04%	9.34%	12.19%	12.80%
13	PGN	PROGRESSS ENERGY	2.13%	4.80%	5.00%	1.00%	2.00%	-4.50%	2.50%	3.00%	1.97%	-5.76%	1.93%	1.71%
14	SRE	SEMPRA ENERGY	8.50%	7.00%	6.00%	9.00%	8.00%	10.00%	3.50%	16.50%	8.57%	9.07%	5.53%	16.72%
15	WR	WESTAR ENERGY, INC.	18.31%	6.00%	2.00%	5.50%	4.50%	32.00%	-5.00%	-4.50%	5.79%	5.59%	5.55%	7.69%
16	WEC	WISCONSIN ENERGY CORPORATION	6.76%	9.40%	8.00%	9.50%	6.50%	9.00%	-1.00%	7.00%	6.91%	5.88%	5.74%	7.40%
17	XEL	XCEL ENERGY INC.	4.29%	6.00%	7.50%	3.00%	4.50%	-2.00%	-8.50%	-1.50%	1.29%	2.35%	4.95%	3.22%
18					5.56%	5.75%	5.66%	4.67%	3.38%	6.00%		6.06%	6.08%	7.47%
19	AVERAGES		7.13%	7.64%		5.66%			4.68%		5.55%		6.54%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 09/26/2008, 11/07/2008 AND 11/28/2008
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 09/26/2008, 11/07/2008 AND 11/28/2008
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THROUGH 17
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 09/26/2008, 11/07/2008 AND 11/28/2008

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	ALLETTE, INC.	k	=	2.02%	+ [	0.85	x (	10.40%	-	5.30%	)]	=	6.36%
2	LNT	ALLIANT ENERGY	k	=	2.02%	+ [	0.80	x (	10.40%	-	5.30%	)]	=	6.10%
3	AEE	AMEREN CORP.	k	=	2.02%	+ [	0.80	x (	10.40%	-	5.30%	)]	=	6.10%
4	EXC	EXELON CORPORATION	k	=	2.02%	+ [	0.90	x (	10.40%	-	5.30%	)]	=	6.61%
5	FE	FIRSTENERGY CORP.	k	=	2.02%	+ [	0.85	x (	10.40%	-	5.30%	)]	=	6.36%
6	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	k	=	2.02%	+ [	0.75	x (	10.40%	-	5.30%	)]	=	5.85%
7	MDU	MDU RESOURCES GROUP	k	=	2.02%	+ [	1.00	x (	10.40%	-	5.30%	)]	=	7.12%
8	OTTR	OTTER TAIL CORPORATION	k	=	2.02%	+ [	0.85	x (	10.40%	-	5.30%	)]	=	6.36%
9	PCG	PG&E CORPORATION	k	=	2.02%	+ [	0.85	x (	10.40%	-	5.30%	)]	=	6.36%
10	PNW	PINNACLE WEST CAPITAL CORPORATION	k	=	2.02%	+ [	0.80	x (	10.40%	-	5.30%	)]	=	6.10%
11	PNM	PNM RESOURCES	k	=	2.02%	+ [	0.85	x (	10.40%	-	5.30%	)]	=	6.36%
12	PPL	PPL CORPORATION	k	=	2.02%	+ [	0.80	x (	10.40%	-	5.30%	)]	=	6.10%
13	PGN	PROGRESSS ENERGY	k	=	2.02%	+ [	0.60	x (	10.40%	-	5.30%	)]	=	5.08%
14	SRE	SEMPRA ENERGY	k	=	2.02%	+ [	0.95	x (	10.40%	-	5.30%	)]	=	6.87%
15	WR	WESTAR ENERGY, INC.	k	=	2.02%	+ [	0.85	x (	10.40%	-	5.30%	)]	=	6.36%
16	WEC	WISCONSIN ENERGY CORPORATION	k	=	2.02%	+ [	0.75	x (	10.40%	-	5.30%	)]	=	5.85%
17	XEL	XCEL ENERGY INC.	k	=	2.02%	+ [	0.80	x (	10.40%	-	5.30%	)]	=	6.10%
18	**AVERAGE**						0.83							6.24%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) THE YIELD ON A 5-YEAR TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION ON 11/28/08 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE GEOMETRIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2007 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2008 YEARBOOK.

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
CAPM COST OF EQUITY CAPITAL

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	ALLETTE, INC.	k	=	2.02%	+ [	0.85	x (	12.30%	-	5.50%	)]	=	7.80%
2	LNT	ALLIANT ENERGY	k	=	2.02%	+ [	0.80	x (	12.30%	-	5.50%	)]	=	7.46%
3	AEE	AMEREN CORP.	k	=	2.02%	+ [	0.80	x (	12.30%	-	5.50%	)]	=	7.46%
4	EXC	EXELON CORPORATION	k	=	2.02%	+ [	0.90	x (	12.30%	-	5.50%	)]	=	8.14%
5	FE	FIRSTENERGY CORP.	k	=	2.02%	+ [	0.85	x (	12.30%	-	5.50%	)]	=	7.80%
6	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	k	=	2.02%	+ [	0.75	x (	12.30%	-	5.50%	)]	=	7.12%
7	MDU	MDU RESOURCES GROUP	k	=	2.02%	+ [	1.00	x (	12.30%	-	5.50%	)]	=	8.82%
8	OTTR	OTTER TAIL CORPORATION	k	=	2.02%	+ [	0.85	x (	12.30%	-	5.50%	)]	=	7.80%
9	PCG	PG&E CORPORATION	k	=	2.02%	+ [	0.85	x (	12.30%	-	5.50%	)]	=	7.80%
10	PNW	PINNACLE WEST CAPITAL CORPORATION	k	=	2.02%	+ [	0.80	x (	12.30%	-	5.50%	)]	=	7.46%
11	PNM	PNM RESOURCES	k	=	2.02%	+ [	0.85	x (	12.30%	-	5.50%	)]	=	7.80%
12	PPL	PPL CORPORATION	k	=	2.02%	+ [	0.80	x (	12.30%	-	5.50%	)]	=	7.46%
13	PGN	PROGRESSS ENERGY	k	=	2.02%	+ [	0.60	x (	12.30%	-	5.50%	)]	=	6.10%
14	SRE	SEMPRA ENERGY	k	=	2.02%	+ [	0.95	x (	12.30%	-	5.50%	)]	=	8.48%
15	WR	WESTAR ENERGY, INC.	k	=	2.02%	+ [	0.85	x (	12.30%	-	5.50%	)]	=	7.80%
16	WEC	WISCONSIN ENERGY CORPORATION	k	=	2.02%	+ [	0.75	x (	12.30%	-	5.50%	)]	=	7.12%
17	XEL	XCEL ENERGY INC.	k	=	2.02%	+ [	0.80	x (	12.30%	-	5.50%	)]	=	7.46%
18	**AVERAGE**						0.83							7.64%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\ ß\,(r_m - r_f)\ ]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) THE YIELD ON A 5-YEAR TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION ON 11/28/08 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2007 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2008 YEARBOOK.

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.00%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	CURRENT	4.55%	-0.50%	4.00%	1.25%	0.25%	0.06%	3.91%	7.34%	8.20%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 11/28/2008
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 11/28/2008
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

NOTE:
(a) RESULT OF A 75 BASIS POINT RATE CUT ANNOUNCED ON DECEMBER 16, 2008

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. E-01345A-08-0172
SCHEDULE WAR - 9

LINE NO.									
		ALE	PCT.	LNT	PCT.	AEE	PCT.	EXC	PCT.
1	DEBT	$ 410.9	35.6%	$ 1,404.5	32.4%	$ 3,208.0	47.1%	$ 11,965.0	54.1%
2									
3	PREFERRED STOCK	0.0	0.0%	243.8	5.6%	113.0	1.7%	87.0	0.4%
4									
5	COMMON EQUITY	742.6	64.4%	2,681.2	61.9%	3,488.0	51.2%	10,050.0	45.5%
6									
7	TOTALS	$ 1,153.5	100%	$ 4,329.5	100%	$ 6,809.0	100%	$ 22,102.0	100%
8									
9									
10		FE	PCT.	HE	PCT.	MDU	PCT.	OTTR	PCT.
11									
12	DEBT	$ 8,869.0	49.7%	$ 1,242,099.0	49.3%	$ 1,146,781.0	31.2%	$ 342,694.0	38.8%
13									
14	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	15,000.0	0.4%	15,500.0	1.8%
15									
16	COMMON EQUITY	8,977.0	50.3%	1,275,427.0	50.7%	2,516,319.0	68.4%	523,902.0	59.4%
17									
18	TOTALS	$ 17,846.0	100%	$ 2,517,526.0	100%	$ 3,678,100.0	100%	$ 882,096.0	100%
19									
20									
21		PCG	PCT.	PNW	PCT.	PNM	PCT.	PPL	PCT.
22									
23	DEBT	$ 7,891.0	46.4%	$ 3,127,125.0	47.0%	$ 1,231,859.0	42.0%	$ 6,890.0	54.0%
24									
25	PREFERRED STOCK	145.0	0.9%	0.0	0.0%	11,529.0	0.4%	301.0	2.4%
26									
27	COMMON EQUITY	8,980.0	52.8%	3,531,611.0	53.0%	1,692,411.0	57.6%	5,575.0	43.7%
28									
29	TOTALS	$ 17,016.0	100%	$ 6,658,736.0	100%	$ 2,935,799.0	100%	$ 12,766.0	100%
30									
31									
32		PGN	PCT.	SRE	PCT.	WR	PCT.	WEC	PCT.
33									
34	DEBT	$ 8,737.0	50.4%	$ 4,553.0	34.8%	$ 1,889,781.0	50.6%	$ 3,172.5	50.3%
35									
36	PREFERRED STOCK	93.0	0.5%	179.0	1.4%	21,436.0	0.6%	30.4	0.5%
37									
38	COMMON EQUITY	8,506.0	49.1%	8,339.0	63.8%	1,827,044.0	48.9%	3,099.2	49.2%
39									
40	TOTALS	$ 17,336.0	100%	$ 13,071.0	100%	$ 3,738,261.0	100%	$ 6,302.1	100%
41									
42									
43		XEL	PCT.						
44									
45	DEBT	$ 6,342,160.0	49.7%						
46									
47	PREFERRED STOCK	104,980.0	0.8%						
48									
49	COMMON EQUITY	6,301,002.0	49.4%						
50									
51	TOTALS	$ 12,748,142.0	100%						
52									
53		ELECTRIC COMPANY SAMPLE							
54		AVERAGE	PCT.						
55									
56	DEBT	$ 15,379,599.9	46.2%						
57									
58	PREFERRED STOCK	169,637.2	0.5%						
59									
60	COMMON EQUITY	17,728,154.0	53.3%						
61									
62	TOTALS	$ 33,277,391.1	100%						

REFERENCE:
MOST RECENT SEC 10(k) FILINGS OR COMPANY ANNUAL REPORTS