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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, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-11-0224

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of William A. Rigsby and Frank Radigan, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 18th day of November, 2011.

Daniel W. Pozefsky
Chief Counsel

Arizona Corporation Commission
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ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 18, 2011

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EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's analysis of Arizona Public Service Company's application for a permanent rate increase, filed with the Arizona Corporation Commission on June 1, 2011, RUCO recommends the following:

Cost of Equity – RUCO recommends that the Commission adopt a 10.00 percent cost of common equity. This 10.00 percent figure falls just above the high side of the range of results obtained in RUCO's cost of equity analysis, and is 100 basis points lower than Arizona Public Service Company's proposed 11.00 percent cost of common equity.

Capital Structure – RUCO recommends that the Commission adopt Arizona Public Service Company's proposed capital structure comprised of 53.94 percent common equity and 46.06 percent long-term debt.

Cost of Debt – RUCO recommends that the Commission adopt RUCO's recommended cost of Long-term debt of 6.26 percent which is 12 basis points lower than the 6.38 percent cost of long-term debt being proposed by Arizona Public Service Company.

EXECUTIVE SUMMARY (Cont.)

Original Cost Rate of Return – RUCO recommends that the Commission adopt an 8.27 percent weighted average cost of capital as the original cost rate of return for Arizona Public Service Company This 8.27 percent figure is the weighted cost of RUCO's recommended costs of common equity and long-term debt, and is 73 basis points lower than the 8.87 percent weighted average cost of capital being proposed by Arizona Public Service Company.

Fair Value Rate of Return – RUCO recommends that the Commission adopt a fair value rate of return of 6.10 percent which is RUCO's 8.27 percent original cost rate of return minus RUCO's recommended inflation adjustment of 2.18 percent. The method used by RUCO to arrive at this 6.10 percent figure is consistent with the methods adopted by the Arizona Corporation Commission in the prior UNS Gas, Inc. and UNS Electric, Inc. rate case proceedings.

INTRODUCTION

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

A. My Name is William A. Rigsby. I am the Chief of Accounting and Rates for 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 utilities regulation and your educational background.

A. I have been involved with utilities 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 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 I, which is attached to my direct 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 based on my analysis of Arizona Public Service Company's ("APS" or the "Company") application for a permanent increase in rates ("Application").

Q. Is this your first case involving APS?

A. No. I've testified in two previous APS rate cases that have come before the Commission.

Q. Briefly describe APS and the Company's filing.

A. APS is based in Phoenix, Arizona and is the largest investor-owned electric utility in the state and serves customers in eleven of fifteen Arizona counties. According to the most recent Value Line Investment Survey ("Value Line") report on the Company, APS provides electricity to approximately 1.1 million customers comprised of 47.00 percent residential, 39.00 percent commercial, 5.00 percent industrial, and 9.00 percent other. APS' generating sources include coal, 37.00 percent; nuclear, 27.00 percent; natural gas, 12.00 percent; and purchased power, 24.00 percent. Fuel costs comprised 36.00 percent of the Company's revenues. The Company has approximately 7,200 employees.

APS' 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"). The Company has an ownership interest in the Palo Verde Nuclear Generating Station, 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.

Q. Has APS elected to perform a reconstruction cost new less depreciation study in this case?

A. Yes. APS elected to perform a reconstruction cost new less depreciation ("RCND") study and is proposing a fair value rate base ("FVRB") that is an average of the Company's original cost rate base ("OCRB") and its RCND rate base for ratemaking purposes. For this reason RUCO is recommending a fair value rate of return ("FVROR") to be applied to APS' FVRB.

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

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case and will present RUCO's OCROR and FVROR recommendations.

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 six sections. First, the introduction I have just presented and second, a 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 return for utilities that operate in the Arizona jurisdiction. In this third section I will also provide a brief overview of the current economic climate within which the Company is operating. Fourth, I will discuss my recommended capital structure and my recommended cost of long-term debt. Fifth, I will discuss my recommended weighted average costs of capital for both my recommended OCROR and FVROR. In the sixth and final section of my testimony, I will comment on the Company's 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, I am making the following recommendations:

<u>Cost of Equity Capital</u> – I am recommending that the Commission adopt a 10.00 percent cost of common equity. This 10.00 percent figure is 23 basis points higher than the range of results obtained in my cost of equity analysis, and is 100 basis points lower than APS' proposed 11.00 percent cost of common equity.

Capital Structure – I am recommending that the Commission adopt APS' proposed capital structure comprised of 53.94 percent common equity and 46.06 percent long-term debt.

Cost of Debt – I am recommending that the Commission adopt a cost of long-term debt of 6.26 percent which is 12 basis points lower than the 6.74 percent cost of long-term debt being proposed by the Company.

Original Cost Rate of Return – I am recommending that the ACC adopt an 8.27 percent weighted average cost of capital as the original cost rate of return ("OCROR") for APS. This 8.27 percent figure is the weighted cost of RUCO's recommended costs of common equity and long-term debt, and is 60 basis points lower than the 8.87 percent weighted average cost of capital being proposed by the Company.

Fair Value Rate of Return – I am recommending that the Commission adopt a fair value rate of return ("FVROR") of 6.10 percent which is my recommended 8.27 percent OCROR minus an inflation adjustment of 2.18 percent. The method I have used to arrive at this 6.10 percent figure is consistent with methods adopted by the Commission in prior rate case proceedings[1] and meets the fair value requirement of the Arizona

[1] UNS Electric, Inc., Decision No. 71914, dated September 30, 2010 and UNS Gas, Inc., Decision No. 71623, dated April 14, 2010

Constitution. It is also the same method recommended by RUCO witness Dr. Ben Johnson in the Southwest Gas Corporation rate case proceeding[2] that is now before the ACC.

Q Why do you believe that RUCO's recommended 8.27 percent OCROR and 6.10 percent FVROR are appropriate rates of return for APS to earn on its invested capital?

A. Both the OCROR and FVROR figures that I am recommending for APS meet the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (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 <u>Hope</u> 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

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[2] Docket No. G-01551A-10-0458

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 <u>Bluefield</u> and <u>Hope</u> 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 <u>Bluefield</u> and <u>Hope</u> 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 final recommended cost of equity capital for APS?

A. I am recommending a cost of equity of 10.00 percent (before any inflation adjustment used to arrive at a FVROR). My recommended 10.00 percent cost of equity figure falls just above the high side of the range of results derived from my DCF and CAPM analyses, which utilized a sample of publicly traded LDCs. The results of my DCF and CAPM analyses are summarized on page 3 of my Schedule WAR-1.

Discounted Cash Flow (DCF) Method

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

Q. In determining the rate of future dividend growth for the Company, 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 x 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.[3]

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%

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

[3] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

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[4] 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.[5] 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.

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

[5] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be 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 in only 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,[6] 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

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

			accrues to a current shareholder, and
	v	=	funds raised from the sale of stock as a fraction of existing equity.
and	v	=	1 - [(BV) ÷ (MP)]
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.

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

A. Yes. In a prior Southwest Gas Corporation rate case[7], 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 comprised of twenty publicly traded electric service providers.

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

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. Although Pinnacle West Capital Corporation, APS' parent company, is publicly-traded on the NYSE, APS is not. Because of this situation, I used the aforementioned proxy that includes twenty electric utilities with similar

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

risk characteristics as APS in order to derive a cost of common equity for the Company.

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 Hope 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 electric utilities included in your proxy for APS?

A. Each of the electric utilities in my sample are tracked in the Value Line Investment Survey's ("Value Line") Electric Utility industry segment. Value Line follows electric utilities on a regional basis and issues quarterly updates on electric utilities located in the eastern, central and western portions of the U.S. All of the companies in the proxy are engaged in the provision of regulated electric services. Attachment A of my testimony contains Value Line's most recent evaluation on each of the twenty companies that I included in the electric proxy group that I used for my cost of common equity analysis.

Q. Are these the same electric providers included in the proxy used by APS' cost of equity witness?

A. With the exception of Pinnacle West Capital Corporation, the parent company of APS, these are the same electric providers used by William E. Avera, Ph.D., the Company's' cost of capital witness.

Q. Why did you exclude Pinnacle West Capital Corporation from your proxy group?

A. I excluded Pinnacle West Capital Corporation from my proxy group for two reasons. First, Value Line inadvertently omitted 2008 operating results for Pinnacle West Capital Corporation in their November 4, 2011 quarterly update on electric utilities located in the western region of the U.S. Upon discovering the omission I contacted Value Line to find out if a correction was going to be issued and was told by Mr. Paul Debbas that Value Line was not going to make a correction until their next quarterly update is published. A second, and possibly sounder, reason for omitting Pinnacle West Capital Corporation is simply that it is probably best not to include the parent of the company that is the subject of an analysis, since the object of the analysis is to determine a cost of equity figure for utilities with similar risk characteristics.

...

Q. Please explain your DCF growth rate calculations for the sample electric providers 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 electric companies included in my sample for an historical 5-year observation period from the beginning of 2006 to the end of 2010. Schedule WAR-5 also includes Value Line's projected 2011, 2012 and 2014-16 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the sample electric companies.

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 11 and 12 of my testimony) to multiply AEE's earned return on common equity by its earnings retention ratio for each year in the 2006 to 2010 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 average internal growth rate of 2.18 percent over the 2006 to 2010 time frame reflects an up and down pattern of growth that ranged from a low of 1.03 percent in 2008 to a high of 3.82 percent during 2010. Value Line is predicting that growth will fall to 2.51 percent in 2011 and 2012 before increasing to 2.69 percent by the end of the 2014-16 time frame. After weighing Value Line's projections on earnings and dividend growth, I believe that a 3.00 percent rate of internal growth is within the realm of possibility for AGL (Schedule WAR-4, Page 1 of 2).

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

A. Schedule WAR-5 demonstrates that the number of shares outstanding for AEE increased from 206.60 million to 240.40 million from 2006 to 2010. Value Line is predicting that this level will increase from 244.00 million in 2011 to 256.00 million by the end of 2016. Based on this data, I believe that a 1.40 percent growth in shares is not unreasonable for AEE (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for AEE is 5.70 percent (3.00 percent internal growth + 2.75 percent external growth – as calculated on Page 2 of Schedule WAR 4) and is shown on Page 1 of Schedule WAR-4.

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

A. The average DCF dividend growth rate estimate for my sample is 5.59 percent as displayed on page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate estimates on your sample companies compare to the growth rate data published by Value Line and other analysts?

A. Schedule WAR-6 compares my growth estimates with the five-year projections of analysts at both Value Line and Zacks Investment Research, Inc. ("Zacks") (Attachment B). My 5.59 percent estimate exceeds Zacks' average long-term EPS projection of 2.37 percent and is 43 basis points higher than Value Line's growth projection of 5.16 percent (which is an average of EPS, DPS and BVPS). My 5.59 percent estimate is 252 basis points higher than the 3.07 percent average of Value Line's historical growth results and 108 basis points higher than the 4.01 percent average of the growth data published by both Value Line and Zacks. My 5.59 percent growth estimate is 186 basis points higher than Value Line's 3.73 percent 5-year compound historical average of EPS, DPS and BVPS. The estimates of analysts at Value Line indicate that investors are expecting somewhat lower growth than what I am estimating from the electric utility industry in the future. On balance, I would say my 5.59

percent estimate is somewhat more optimistic than the growth projections that are available to the investing public.

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

A. I used the estimated annual dividends of my sample companies for the next twelve-month period that appeared in Value Line's most recent Ratings and Reports quarterly updates on the electric utility industry. I then divided those figures by the eight-week average daily adjusted closing price per share of the appropriate utility's common stock. The eight-week observation period ran from September 12, 2011 to November 4, 2011, and the average dividend yield was 4.17 percent as exhibited on Schedule WAR-3.

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

A. As shown on Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.77 percent for the electric utilities included in my sample.

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 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.

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

[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.

Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM is 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,
	$ß$	=	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 (Attachment C) 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 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

[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.

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 an eight-week average of the yield on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated September 23, 2011 through November 11, 2011 (Attachment C). This resulted in a risk-free (r_f) rate of return of 0.97 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 total returns on the S&P 500 index from 1926 to 2010 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 total returns of intermediate-term government bonds for the same eighty-four year period. The market risk premium (r_m - r_f) that results by using the geometric mean of these inputs is 4.50 percent (9.90% - 5.40% = 4.50%). The market risk premium that results by using the arithmetic mean calculation is 6.40 percent (11.90% - 5.50% = 6.40%).

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

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of September 9, 2011 for the LDCs in my proxy. 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 electric companies included in my sample ranged from 0.55 to 0.80 with an average beta of 0.75.

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 to calculate the risk premium results in an average expected return of 4.32 percent. My calculation using an arithmetic mean results in an average expected return of 5.74 percent.

Q. What would be the expected return if a longer term 30-year U.S. Treasury bond were used as the risk free asset in the CAPM model?

A. During the eight week period that I relied on in my analysis, the yield on a 30-year U.S. Treasury bond declined from 3.27 percent to 3.01 percent. If a 3.01 percent eight-week average of 30-year U.S. Treasury bond yields were used in my CAPM model it would produce expected returns of 6.29 percent using a geometric mean, and 7.49 percent using an arithmetic mean. As I will discuss later in my testimony, the yields of long-term U.S. Treasury instruments are currently falling as a result of recent actions being undertaken by the U.S. Federal Reserve.

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	9.77%
CAPM	4.32% – 5.74%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 4.32 percent to 9.77 percent. My final recommended cost of common equity figure is 10.00 percent which is just above the high end of the range of estimates shown above (Schedule WAR-1, Page 3).

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

A. The 11.00 percent cost of equity capital proposed by the Company is 100 basis points higher than the 10.00 percent cost of equity capital that I am recommending.

Q. How did you arrive at your final recommended 10.00 percent cost of common equity?

A. As just stated, my recommended 10.00 percent cost of common equity falls just above the high side of the range of estimates obtained from my DCF and CAPM analyses. As I will discuss in more detail in the next section of my testimony, my final estimate takes into consideration current interest rates (as the cost of equity moves in the same direction as interest rates), the current state of the national economy – which could be sliding back into recession. My final estimate also takes into consideration the U.S. Federal Reserve's recent decision not to raise interest rates anytime over the next two years. I also took into consideration information on Arizona's economy and current rate of unemployment in making my final cost of equity estimate. My final estimate also falls within the range of projected returns on book common equity that Value Line is projecting for the electric utility industry.

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 describe your analysis of the current economic environment.

A. My analysis begins with a review of the economic events that have occurred between 1990 and the present in order to provide a background on how we got to where we are now. It also describes how the Board of Governors of the Federal Reserve System ("Federal Reserve" or "Fed") and its Federal Open Market Committee ("FOMC") used its interest rate-setting authority to stimulate the economy by cutting interest rates during recessionary periods and by raising interest rates to control inflation during times of robust economic growth. 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, then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[11] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

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

[11] 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.

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. Over the next ten years, the FOMC continued to stimulate the economy and keep inflation in check by raising and lowering the federal funds rate.

Q. How did the U.S. economy fare between 2001 and 2007?

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. Disappointing economic data releases, since the beginning of 2001, preceded the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon which are now regarded as a defining point during this economic slump. From January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times in order to stimulate growth. 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 during a period in which the economic picture turned considerably brighter as both Inflation and unemployment fell, wages increased and the overall economy, despite continued problems in housing, grew briskly.[12]

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 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. Once again, the Fed managed to engineer a soft landing.

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

Q. What has been the state of the economy since 2007?

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.

On August 7, 2007, the beginning of what is now being referred to as the Great Recession; 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.[13] 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 crisis 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 its open market operations) into the credit markets.[14] By Friday, August 17, 2007, after a

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

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

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, [15] 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 – 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

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

reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What actions has the Fed taken in regard to interest rates since the beginning of 2008?

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).[16] 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 former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has

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

been described as the worst financial crisis since the 1930's[17]. 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.

Q. What is the current rate of inflation in the U.S.?

A. As can be seen on Schedule WAR-8, the current rate of inflation, as measured by the consumer price index, is at 3.90 percent according to information provided by the U.S. Department of Labor's Bureau of Labor Statistics.[18]

Q. Has the Fed raised interest rates in anticipation of higher inflation?

A. No. The FOMC has not raised interest rates to date. The Fed's plan to buy $600 billion of U.S. government bonds over an eight month period, known as quantitative easing stage two or QE2,[19] was completed during the summer of 2011. The attempt to drive down long-term interest rates

[17] 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

[18] http://www.bls.gov/news.release/cpi.nr0.htm

[19] Hilsenrath, Jon, "Fed Fires $600 Billion Stimulus Shot" The Wall Street Journal, November 4, 2010

and encourage more borrowing and growth by increasing the money supply has yet to stimulate the economy and fears of a double dip recession persist. At its August 9, 2011 meeting, the FOMC announced that it intended to keep interest rates at their current levels for at least the next two years warning that the economy would remain weak for some time but that the Fed is prepared to take further steps to shore it up.[20]

Q. Has the Fed taken any recent action, such as QE2, to stimulate the economy?

Yes. At the close of the FOMC's September meeting the Fed announced its decision to implement a plan that resembles a 1961 Federal Reserve program known as "Operation Twist".[21] Under this plan, the Fed will sell $400 billion in Treasury securities that mature within three years. The proceeds from these sales will then be reinvested into securities that mature in six to 30 years. This action would significantly alter the balance of the Fed's holdings toward long-term securities. In addition to selling off its shorter term Treasury holdings, the Fed will take the proceeds from its maturing mortgage-backed securities and reinvest them in other mortgage backed securities. For the past year, the Fed has been reinvesting that money into Treasury bonds, shrinking its mortgage portfolio. The overall

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[20] Reddy, Sudeep and Jonathan Cheng "Markets Sink Then Soar After Fed Speaks" The Wall Street Journal, August 10, 2011

[21] Hilsenrath, Jon and Luca Di Leo "Fed Launches New Stimulus" The Wall Street Journal, September 22, 2011

goal of the Fed's plan is to reduce long-term interest rates in the hope of boosting investment and spending and provide a shot in the arm to the beleaguered housing sector of the economy. During its most recent FOMC meeting held on November 1, 2011, the Fed decided not to make any changes to existing interest rates.

Q. Has there been any noticeable drop in long-term rates since the Fed announced its plan to purchase longer term Treasury instruments?

A. Yes. As I noted earlier in my testimony, the yield on the 30-year Treasury bond has from fallen from 3.27 percent to 3.01 percent since the latter part of September 2011.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected the yields on Treasury Instruments and benchmark interest rates?

A. As can be seen on Schedule WAR-8, current Treasury yields are considerably lower than corresponding yields that existed during the year 2000 and U.S. Treasury instruments, are for the most part, still at historically low levels. As can be seen on the first page of Attachment C, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has remained steady at 0.75 percent since November of 2010.

As of November 4, 2011, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have dropped from their November 2010 levels. Longer term yields including the 5-year, 10-year and 30-year have all fallen from levels that existed a year ago. The same is true for the 30-year Zero rate. The prime rate has remained constant at 3.25 percent over the past year, as has the benchmark federal funds rate discussed above. A previous trend, described by former Chairman Greenspan as a "conundrum"[22], in which long-term rates fell as short-term 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. The 5-year Treasury yield, used in my CAPM analysis, has decreased 23 basis points from 1.11 percent, in November 2010, to 0.88 percent as of November 2, 2011.

Q. What are the current yields on utility bonds?

A. Referring again to Attachment C, as of November 2, 2011, 25/30-year A-rated utility bonds were yielding 4.12 percent (110 basis points lower than a year ago) and 25/30-year Baa/BBB-rated utility bonds were yielding 4.76 percent (down 103 basis points from a year earlier).

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

Q. What is the current outlook for the economy?

A. The current outlook on the economy is that a slide into recession appears to be unlikely but an outlook for slower growth persists. Value line's analysts offered this perspective in the November 11, 2011 edition of Value Line's Selection and Opinion publication:

> "**One by one, the markers pointing to a new recession are falling — at least in this country.** Recent data, for example, affirm that consumer spending, manufacturing orders, and auto sales are pressing higher, while other reports confirm that industrial production and business investment are rallying. Those still calling for a recession, therefore, are getting less and less of an audience."

Value Line's analysts went on to say:

> "**The U.S. upturn could move onto a slower track going forward,** with growth — which rose to 2.5% in the third quarter — perhaps easing to less than 2% this period. Thereafter, there may be some gradual firming in 2012, with growth possibly averaging 2%, or so. Clearly, though, this forecast is tenuous due to uncertainty in Europe, where a recession seems more likely."

Value Line's analysts also stated:

> "**The year ahead holds numerous questions.** First, there is Europe, which is in flux, as prior headlines proclaiming a resolution of the debt crisis now look a bit premature. Then, there are Federal Reserve policies, which are fluid and likely to evolve further, as the central bank seeks a balance between promoting faster growth and containing inflation. Also, there are questions about housing and personal income, both of which are under strain. Finally, there's the likelihood of slower growth in China, which would add to global strains. All of this implies that a stronger showing by our economy in 2012 is unlikely."

Value Line's analysts further went on to say:

> "**Earnings season is now in the books**, and it has been a respectable one for the most part. However, there were fewer fireworks on the upside than in prior quarters, as profit matchups became more difficult after two years of easy growth. We also

> think earnings will press forward in the final quarter, but more modestly."

Q. How are electric utilities such as APS faring in the current economic environment?

A. In the November 4, 2011 quarterly update on the Electric Utility (West) Industry, Value Line analyst Paul E. Debbas, CFA had this to say:

> "Electric utility stocks are known for outperforming the broader market averages in a down market. So far in 2011, this has proven to be the case. The Value Line Geometric Average is down 12% this year, while the Value Line Utility Average is up 2%. When dividends are considered, the relative out performance of this group is even greater. This had made the equities in this industry relatively less attractive, however. In fact, some issues, such as Pinnacle West, are trading around the middle of th eir 2014-2016 Target Price Range. F or a utility stock, this is often a sign that it has become overvalued."

Also Included in Value Line's November 4, 2011 issue is its ranking of each state's regulatory climate, plus that of the District of Columbia and the Federal Energy Regulatory Commission ("FERC"). Value Line ranks states as above average, average and below average. Interestingly, Arizona was ranked as average along with California, Delaware, District of Columbia, Florida, Georgia, Hawaii, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Pennsylvania, Texas, Virginia, Washington and Wyoming.

...

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery.[23] During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties. As of this writing RealtyTrac still ranks Arizona as having the third highest foreclosure rate in the country with one in every ninety-three housing units receiving a foreclosure filing in the third quarter.[24]

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on October 20, 2011, and displayed on the website of the Arizona Department of Administration's Office of Employment and Population Statistics,[25] the seasonally adjusted unemployment rate for Arizona dropped two tenths of a percentage point

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[23] Beard, Betty, "Recession hit Arizona hardest" The Arizona Republic, March 6, 2011

[24] Millar, DiAngelea, "RealtyTrac: Arizona home foreclosures down sharply," Phoenix Business Journal, October 13, 2011.

[25] Arizona Department of Administration's Office of Employment and Population Statistics http://www.workforce.az.gov/

from 9.3% in August, to 9.1% in September. At the time that this information was compiled, Arizona's rate of unemployment mirrored the U.S. unemployment rate which remained unchanged at 9.1% for the third consecutive month. In September 2010 the U. S. rate was 9.6% and Arizona's rate was 9.8%[26] as can be seen below:

Arizona, U.S. Economic Indicators
Unemployment Rate (Seasonally Adj.)

	Sep '11	Aug '11	Sep '10
United States	9.1%	9.1%	9.6%
Arizona	9.1%	9.3%	9.8%
Arizona unadjusted rate	8.9%	9.4%	9.8%

More recent information on the national rate of unemployment, released by the U.S. Department of Labor on November 4, 2011, has pegged U.S. unemployment at 9.00 percent.

According to the October 20, 2011 Arizona Department of Administration's Office of Employment and Population Statistics report, the September 2011 rates of unemployment for the counties that are served by APS were as follows:

Selected County Unemployment Rates - September 2011

Apache	15.0%
Cochise	8.2%
Coconino	7.3%
Gila	9.7%
La Paz	9.5%
Maricopa	7.9%
Navajo	14.0%

[26] U.S. Bureau of Labor Statistics Economic News Release dated June 3, 2011 http://www.bls.gov/news.release/empsit.nr0.htm

Pima	8.0%
Pinal	10.6%
Yavapai	9.4%
Yuma	27.0%

Q. After weighing the economic information that you've just discussed, do you believe that the 10.00 percent cost of equity capital that you have estimated is reasonable for the Company?

A. I believe that my recommended 10.00 percent cost of equity capital, which is 524 basis points higher than the current 4.76 percent yield on a Baa/BBB-rated utility bond, will provide APS with a reasonable rate of return on invested capital when data on interest rates (that are low by historical standards), the current state of the economy, current rates of unemployment (both nationally, in Arizona, and in the counties served by APS), and the Fed's decision to keep interest rates at their current levels over the next two years are all 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 cost of equity analysis, which is on the high side of the range of results I obtained from both the DCF and CAPM models, has produced such a return.

CAPITAL STRUCTURE AND COST OF DEBT

Q. Please describe the Company-proposed capital structure.

A. The Company-proposed end of test year capital structure is comprised of 53.94 percent common equity and 46.06 percent long-term debt.

Q. How does the Company-proposed capital structure compare with the capital structures of the electric companies that comprise your sample?

A. The Company-proposed capital structure containing 53.94 percent common equity is somewhat higher in equity than the capital structures of the electric companies in my sample, which had an average of 45.70 percent common equity, and would be perceived by investors as having somewhat lower risk overall. APS' 46.06 percent level of long-term debt is lower than the average of 53.60 percent in my sample and would be perceived as having a lower level of financial risk. Overall I would say that APS' capital structure is fairly well balanced.

Q. What capital structure are you recommending for APS?

A. I am recommending that he Commission adopt the Company-proposed capital structure comprised of 53.94 percent common equity and 46.06 percent long-term debt.

Q. What cost of long-term debt are you recommending for APS?

A. I am recommending that the Commission adopt a cost of Long-term debt of 6.26 percent which, based on my calculation of the Company's various outstanding debt instruments, is 12 basis points lower than the 6.38 percent cost of long-term debt being proposed by APS.

WEIGHTED COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. What original cost weighted average cost of capital are you recommending for APS?

A. Based on my recommended capital structure, comprised of 53.94 percent common equity and 46.06 percent long-term debt, I am recommending an original cost weighted average cost of capital of 8.27 percent (Schedule WAR-1, Page 1). This is the weighted average cost of my recommended cost of 10.00 percent common equity and my recommended 6.26 percent cost long-term debt. My 8.27 percent weighted average cost of capital is also the OCROR to be applied to APS' original cost rate base.

Q. What fair value rate of return are you recommending for APS?

A. I am recommending a FVROR of 6.10 percent (Schedule WAR-1, Page 1) which is my OCROR minus an inflation factor of 2.18 percent (Schedule WAR-1, Page 4). My recommended FVROR satisfies the fair value requirement of the Arizona Constitution which the Commission must follow when setting rates for investor owned utilities such as APS.

Q. Why are you recommending a FVROR that is different from your OCROR?

A. Because APS elected not to use the Company's original cost rate base ("OCRB") as its fair value rate base ("FVRB") in this case. Instead, APS performed a reconstruction cost new less depreciation ("RCND") study to restate the value, or reproduction cost, of the Company's OCRB. As is the normal ratemaking practice in Arizona, the Company averaged the values of its OCRB and its RCND rate base to arrive at a FVRB that is higher than the OCRB. This is because the value of the FVRB reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Since the difference in the value of the OCRB and the FVRB represents inflation, as opposed to additional investor supplied capital, an OCROR which includes an inflation component cannot be applied to the FVRB. To do so would result in a double counting of inflation. For this reason it is necessary to remove the inflation component that is included in the OCROR.

Q. Does your recommended FVROR satisfy the requirements for determining a FVROR that resulted from the Commission's Chaparral City Water Company remand decision, which established the need to remove the inflation component from an OCROR?

A. Yes. On July 28, 2008, the Commission issued Decision No. 70441, in which stated the following:

> Our previous method was a shorthand method of ensuring that inflation would only influence one piece of the ratemaking formula - the rate of return. However, the Court of Appeals has made it clear that, under our constitution, the "inflation component" belongs in the FVRB. Accordingly, in order to avoid over-counting the effect of inflation, it is necessary for us to ensure that the rate of return does not also carry an inflation component. [Decision No. 70441, p. 33]

Q. How did you remove the inflation component from your OCROR?

A. By reducing my recommended costs of common equity and long-term debt by an inflation factor of 2.18 percent. This produced my recommended FVROR of 6.10 percent. The method that I have used in this case produces a FVROR that is comparable to the FVROR calculated for UNS Electric, Inc. in a prior rate case proceeding. In that case the Commission adopted a method that reduced the OCROR by an inflation factor that was recommended by RUCO.[27] The Commission had previously used the same method in a rate case proceeding for UNS Electric, Inc.'s sister utility, UNS Gas, Inc. Under the Commission's adopted methodology in the prior UNS Inc. cases, my recommended OCROR of 8.27 percent would be reduced by my recommended 2.18 percent inflation factor – thus resulting in a FVROR of 6.10 percent. The method that I have used in this case, which removes the inflation factor from both my recommended cost of equity and recommended cost of debt, produces an identical 5.96 percent FVROR.

[27] Decision No. 71914, dated September 30, 2010

Q. How did you calculate your inflation factor of 2.18 percent?

A. By using the same RUCO methodology that produced an inflation factor similar to what the Commission relied on in the prior UNS Electric, Inc. case cited above. As can be seen on Page 4 of Schedule WAR-1, my recommended 2.18 percent inflation factor represents the difference between Treasury Inflation-Protected Securities ("TIPS") and comparable securities issued by the U.S. Treasury with similar liquidity and duration over a nine year period.

Q. How does your FVROR compare to the FVROR being recommended by APS?

A. My recommended FVROR of 6.10 percent is 30 basis points lower than the 6.47 percent FVROR being proposed by APS.

Q. What inflation factor does APS propose?

A. APS does not reduce its proposed cost of common equity by an inflation factor. As stated on page 4 of his direct testimony, APS' cost of equity witness Dr. William E. Avera states that the Company-proposed 11.00 percent cost of common equity needs no adjustment since his DCF and CAPM results were obtained using analysts' forward looking estimates based on current market values.

Q. **Do you agree with Dr. Avera's rationale as to why no inflation adjustment is needed to reduce the Company-proposed OCROR?**

A. No. I do not since analysts' forward looking estimates would only take future expected inflation into account. Relying on analysts' forecasted estimates does not address the impact of inflation and other factors which tend to contribute to an upward growth in the value of plant assets over time which is reflected in the Company's RCND rate base which I explained above.

COMMENTS ON THE COMPANY-PROPOSED COST OF EQUITY CAPITAL

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 issues that APS' has raised in its Application.

...

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 11.00 percent which is 100 basis points higher than my recommended 10.00 percent cost of equity.

Q. Have you studied the specific methods that 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 estimates ranging from 9.50 percent to 11.20 percent and his DCF analysis using a sample of unregulated industrials, or non-utilities, produced estimates ranging from 11.90 percent to 12.50 percent. My DCF analysis, which relied on a sample with all but one (Pinnacle West Capital Corporation, the parent of APS) of the regulated electric utilities included in Dr. Avera's sample, produced a final estimate of 9.77 percent.

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. Furthermore the results obtained by Dr. Avera's non-utilities sample clearly demonstrate that these firms are much more riskier than regulated utilities.

...

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 4.53 percent as opposed to my average dividend yield of 4.17 percent. I attribute the majority of the 36 basis point difference to higher closing stock prices that I recorded during my more recent 8-week observation period since there is not that much difference in the annualized dividends paid by our respective sample companies.

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

A. Dr. Avera's electric utilities DCF analysis produced average growth estimates of 4.97 percent to 6.67 percent compared to my 5.59 percent estimate. However, as I will discuss later, Dr. Avera's estimates ignore high and low estimates obtained from his model.

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 also relied on projections from IBES in addition to my reliance on Value Line and Zacks. He also performed a br + sv type calculation similar to what I have done. The IBES growth projections of 5.83 percent were 24 basis points higher than my 5.59 percent average growth estimate. 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.

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 11.40 percent for his sample of electric utilities and an estimate of 10.00 percent for his sample of unregulated industrials. His estimates are 708 basis points to 568 basis points higher than my 4.32 percent CAPM estimate that uses a geometric mean and are 566 basis points to 426 basis points higher than my 5.74 percent CAPM estimate that uses an arithmetic mean. When compared to my CAPM estimates that relied on an eight-week average 30-year U.S. Treasury bond yield as the risk free rate of return, Dr. Avera's utility sample estimates are 511 basis points higher than my 6.29 percent estimate using a geometric mean, and 391 basis points higher than my 7.49 percent estimate using an arithmetic mean. Dr. Avera's 11.40 percent utility sample estimate exceeds the recent yield of 4.67 percent on a Baa/BBB-rated utility bond yield by 673 basis points.

Q. **What are the main reasons for Dr. Avera's higher CAPM results?**

A. The much higher inputs that include his risk free rate of return and Dr. Avera's market risk premium which 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. Dr. Avera CAPM expected return estimates also include a size adjustment of 0.074 percent for his utility sample and negative 0.37 percent for his unregulated industrials.

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

A. As noted above, there are two main differences between Dr. Avera's CAPM analysis and mine. The first difference involves Dr. Avera's use of a 4.50 percent one month average of the higher yields of 30-year Treasury bonds as opposed to the more recent 8-week average yields 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. Dr. Avera's market risk premium is the 12.8 percent sum of yields and growth rates of S&P 500 dividend paying firms recorded on January 28, 2011 and February 23, 2011 respectively minus the aforementioned 4.50 percent risk free rate, used by Dr. Avera, as opposed to the SBBI data that I relied on that encompassed a much broader period of the U.S. economy between 1926 and 2010. Dr. Avera's method results in a market risk premium of 8.30 percent (12.80% - 4.50% = 8.30%) as opposed to my risk premiums of 4.50 percent and 6.40 percent based on a geometric and arithmetic mean respectively.

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 4.50 percent as opposed to my risk free rate of 0.97 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 30-year Treasury bond instrument is currently yielding 3.01 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's utility sample had an average Value Line beta of 0.74 as opposed to my average Value Line beta of 0.75 (using a sample that excluded Pinnacle West Capital Corporation). Dr. Avera's beta for unregulated industrials was 0.71.

Q. What is the beta of Pinnacle West Capital Corporation, the parent of APS?

A. Pinnacle West Capital Corporation has a Value Line beta of 0.70 which is lower than Dr. Avera's average utility sample beta of 0.74 and my average beta of 0.75. This indicates that APS' parent company is not as risky as the average of our respective sample electric utilities.

Q. How did Dr. Avera arrive at his final 11.00 percent cost of equity capital for APS?

A. Dr. Avera's final cost of equity estimate of 11.00 percent falls within the 9.50 percent to 12.50 percent range of results obtained from his DCF and CAPM models using two sample groups comprised of regulated electric utilities and unregulated industrials.

...

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.

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-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase
UNS Electric, Inc.	E-04204A-06-0783	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
Arizona Public Service Company	E-01345A-08-0172	Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
UNS Gas, Inc.	G-04204A-08-0571	Rate Increase
Arizona Water Company	W-01445A-08-0440	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Black Mountain Sewer Corporation	SW-02361A-08-0609	Rate Increase
Global Utilities	SW-02445A-09-0077 et al.	Rate Increase
Litchfield Park Service Company	SW-01428A-09-0104 et al.	Rate Increase
UNS Electric, Inc.	E-04204A-09-0206	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-08-09-0257	Rate Increase
Arizona-American Water Company	W-01303A-09-0343	Rate Increase
Bella Vista Water Company	W-02465A-09-0411 et al.	Rate Increase
Chaparral City Water Company	W-02113A-10-0309	Reorganization
Qwest Communications International	T-04190A-10-0194 et al.	Merger
Qwest Communications International	T-04190A-10-0194 et al.	Merger
CenturyLink, Inc.	T-04190A-10-0194 et al.	Merger
Southwest Gas Corporation	G-01551A-10-0458	Rate Increase
Arizona-American Water Company	W-01303A-10-0448	Rate Increase
Arizona-American Water Company	W-01303A-11-0101	Reorganization
Bermuda Water Company, Inc.	W-01812A-10-0521	Rate Increase
UNS Gas, Inc.	G-04204A-11-0158	Rate Increase

ATTACHMENT A

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.

In this Issue, we present our rankings of regulatory climates. We have made one change from the previous table, and some other rankings bear watching.

Electric utility stocks are known for their relative outperformance when the broader market averages are down, and 2011 has illustrated this.

Ranking The Regulators

Occasionally, we show a list of each state's regulatory climate, plus that of the District of Columbia and the Federal Energy Regulatory Commission (FERC). Even in states that have undergone partial deregulation of the electric industry, the distribution function is still under the oversight of the regulatory commission. So, this is relevant for every electric utility equity under our coverage. This has become even more important in recent years because rate applications are on the rise. Some companies, such as Great Plains Energy and Duke Energy, have completed or are building large capital projects that need to be placed in the rate base. Others, such as *Avista Energy* and Ameren, are filing more frequently in order to reduce the effects of regulatory lag (i.e., rising costs that aren't reflected in customers' rates).

It is important to understand that our rankings don't just look at regulatory commissions. Other aspects of government, such as the governor, attorney general, legislature, and courts are also considered.

The following listing excludes Alaska, Maine, Nebraska, Rhode Island, Tennessee, and Utah. This is either because there is little or no presence of investor-owned electric companies or because the state's investor-owned electric utilities are subsidiaries of foreign companies that we do not cover.

• *Above Average:* Alabama, Colorado, Idaho, Indiana, Massachusetts, Ohio, South Carolina, South Dakota, Wisconsin, FERC.

• *Average:* Arizona, California, Delaware, District of Columbia, Florida, Georgia, Hawaii, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Pennsylvania, Texas, Virginia, Washington, Wyoming.

INDUSTRY TIMELINESS: 27 (of 98)

• *Below Average:* Arkansas, Connecticut, Illinois, Maryland, New York, Oregon, Vermont, West Virginia.

We have raised South Carolina from Average to Above Average. The state's Base Load Review Act enables utilities to recover construction work in progress for base-load generating facilities. Without this law, SCANA's electric utility subsidiary, South Carolina Electric & Gas, would not be building two nuclear units. We are also considering raising Oregon's regulatory climate to Average. The state government took a positive step earlier this year when it rescinded a tax law that was unique to utilities in the state.

We have not lowered any rankings, but are looking at Massachusetts and FERC. In Massachusetts, the proposed merger between NSTAR and Northeast Utilities has become highly politicized. If the deal fails to win regulatory approval, we will probably lower the regulatory climate a notch. For several years, FERC has granted very healthy returns on equity for transmission investment in order to encourage utilities to boost their spending on electric transmission. However, the question has been raised (by the payers of transmission rates) of whether the incentives are *too* generous. We won't consider cutting FERC's ranking unless it starts cutting the allowed ROEs for transmission. This is of special concern to ITC Holdings, the sole publicly traded transmission-only utility.

Conclusion

Electric utility stocks are known for outperforming the broader market averages in a down market. So far in 2011, this has proven to be the case. The Value Line Geometric Average is down 12% this year, while the Value Line Utility Average is up 2%. When dividends are considered, the relative outperformance of this group is even greater. This had made the equities in this industry relatively less attractive, however. In fact, some issues, such as *Pinnacle West*, are trading around the middle of their 2014-2016 Target Price Range. For a utility stock, this is often a sign that it has become overvalued.

Paul E. Debbas, CFA

Composite Statistics: ELECTRIC UTILITY INDUSTRY

2007	2008	2009	2010	2011	2012		14-16
341.6	363.6	321.0	329.2	*320*	*335*	Revenues ($bill)	*385*
27.4	27.7	27.7	30.1	*29.0*	*31.0*	Net Profit ($bill)	*37.0*
33.1%	33.5%	32.2%	34.2%	*34.0%*	*34.5%*	Income Tax Rate	*34.5%*
6.3%	7.8%	9.2%	8.5%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
50.9%	53.6%	52.4%	52.2%	*51.0%*	*50.5%*	Long-Term Debt Ratio	*50.0%*
48.0%	45.4%	46.6%	47.0%	*48.5%*	*49.0%*	Common Equity Ratio	*49.5%*
467.8	514.0	554.1	585.7	*575*	*605*	Total Capital ($bill)	*695*
505.5	554.4	594.5	640.1	*640*	*680*	Net Plant ($bill)	*780*
7.5%	6.9%	6.5%	6.6%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
11.9%	11.6%	10.5%	10.7%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
12.1%	11.8%	10.6%	10.8%	*10.0%*	*10.0%*	Return on Com Equity	*10.5%*
5.5%	4.9%	4.2%	4.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
55%	58%	61%	59%	*60%*	*61%*	All Div'ds to Net Prof	*59%*
16.9	15.4	12.5	12.9	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.90	.93	.83	.82	*Value Line*		Relative P/E Ratio	*.90*
3.2%	3.8%	4.8%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2008	2009	2010
% Change Retail Sales (kwh)	-1.1	-5.4	+3.6
Average Indust. Use (mwh)	1529	1446	1530
Avg. Indust. Revs. per kwh (¢)	6.66	6.46	6.56
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	+1.6
Fixed Charge Coverage (%)	311	280	305

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

All of the major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

Last month, the Edison Electric Institute spoke about various issues that the electric utility industry is facing. We discuss the industry's concerns.

We note the ways in which the weather has affected electric utilities so far this year.

Electric utility stocks have outperformed the broader market averages, and have been less volatile, during the market turmoil of the past several weeks.

What's On EEI's Mind

The Edison Electric Institute (EEI), an industry group representing investor-owned electric utilities, made a presentation to security analysts last month. It is probably not surprising that the industry is facing issues such as more stringent rules from the U.S. Environmental Protection Agency. On the other hand, investors might be surprised to learn that the Dodd-Frank law, which is targeted for commercial banks, might wind up affecting utilities, too.

Capital spending is increasing. The expenditures of investor-owned electric utilities are projected at over $80 billion a year from 2011 through 2015. (As recently as in 2005, this figure was below $50 billion.) Over the next 20 years, EEI projects that the industry will spend $1.5 trillion-$2.0 trillion on infrastructure, some $200 billion of which will be used to address environmental issues.

This increase is occurring even though the industry is no longer seeing the demand growth that it did not too long ago. The ongoing sluggishness of the economy is one factor. Conservation measures and the increased energy efficiency of appliances are another. What's more, as electric rates are raised to recover higher expenses and place capital projects in the rate base, some price elasticity is evident.

The Dodd-Frank Act, which was enacted in 2010, might also wind up affecting utilities, which trade in power and gas. Many rules will be finalized in 2012 by the U.S. Commodity Futures Trading Commission. Among these are the rules for swaps and swap dealers. If utilities are treated as "dealers," this would cause compliance burdens for the industry. EEI is asking for an end-user exemption that would prevent utilities from having to post margin requirements for transactions.

INDUSTRY TIMELINESS: 5 (of 98)

In July, the Federal Energy Regulatory Commission (FERC) issued a rule concerning electric transmission. Planning and cost allocation have been thorny issues for a while. FERC is trying to encourage competition for transmission projects, although the incumbent utilities will still have the right of first refusal for certain projects. Regional transmission organizations will have to apply the new rules. This is of particular interest for *ITC Holdings*, the sole publicly traded transmission-only utility.

Weather Impacts

The weather always affects electric utilities, but this year has seen some more significant impacts than usual. Hurricane Irene caused power outages for millions of customers, and hurricane season is not yet over. Most notably, the service territory of *Empire District Electric* was devastated by a tornado that hit Joplin, Missouri in May. Initially, the loss of load didn't hurt results much (due in part to hotter-than-normal summer weather), but that's not to say that there won't eventually be any impact.

Many parts of the United States experienced summer weather conditions that were much hotter than normal. Earnings at *OGE Energy*, the parent company of Oklahoma Gas and Electric, will benefit from favorable weather patterns in 2011. Other utilities are likely to post strong third-quarter profits, too.

Flooding in the Midwest will prevent Kansas City Power & Light, the largest subsidiary of *Great Plains Energy*, from receiving as much coal as usual. Thus, the utility will have to use more-costly sources of power (and doesn't have a fuel adjustment mechanism in Missouri). This will hurt its profits in the second half of 2011.

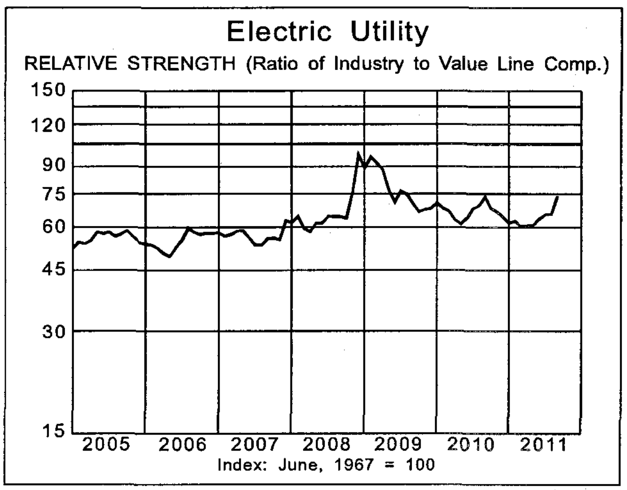
Conclusion

Electric utility stocks have long been known for their defensive characteristics, and this has been evident of late. When the market experienced wide day-to-day swings in August, utility stocks weren't as volatile as the overall market. So far in 2011, the Value Line Utility Average is relatively unchanged, while the Value Line Composite Average has decreased 14%. Most electric utility stocks offer attractive dividend yields, but we caution investors that many are trading within their 2014-2016 Target Price Range.

Paul E. Debbas, CFA

Composite Statistics: Electric Utility Industry

2007	2008	2009	2010	2011	2012		14-16
341.6	363.6	321.0	329.2	**320**	**335**	Revenues ($bill)	**385**
27.4	27.7	27.7	30.1	**29.0**	**31.0**	Net Profit ($bill)	**37.0**
33.1%	33.5%	32.2%	34.2%	**34.0%**	**34.5%**	Income Tax Rate	**34.5%**
6.3%	7.8%	9.2%	8.7%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**6.0%**
50.9%	53.6%	52.4%	52.2%	**51.0%**	**50.5%**	Long-Term Debt Ratio	**50.0%**
48.0%	45.4%	46.6%	47.0%	**48.5%**	**49.0%**	Common Equity Ratio	**49.5%**
467.8	514.0	554.1	585.7	**575**	**605**	Total Capital ($bill)	**695**
505.5	554.4	594.5	640.1	**640**	**680**	Net Plant ($bill)	**780**
7.5%	6.9%	6.5%	6.6%	**6.5%**	**6.5%**	Return on Total Cap'l	**7.0%**
11.9%	11.6%	10.5%	10.7%	**10.0%**	**10.0%**	Return on Shr. Equity	**10.5%**
12.1%	11.8%	10.6%	10.8%	**10.0%**	**10.0%**	Return on Com Equity	**10.5%**
5.5%	4.9%	4.2%	4.5%	**4.0%**	**4.0%**	Retained to Com Eq	**4.5%**
55%	58%	61%	59%	**61%**	**62%**	All Div'ds to Net Prof	**58%**
16.9	15.4	12.5	12.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**13.5**
.90	.93	.83	.83			Relative P/E Ratio	**.90**
6.3%	3.8%	4.8%	4.5%			Avg Ann'l Div'd Yield	**4.3%**



ELECTRIC UTILITY (EAST) INDUSTRY

All the major utilities in the eastern region of the U.S. 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.

Needless to say, it's been a tumultuous couple of months for equity market investors. A slew of mixed economic and political data has sent stocks on a roller coaster ride, including a series of 300+ point swings on the Dow Jones Industrial Average in early August. During these volatile times, investors tend to seek out safe havens for their money, which as far as equities are concerned, usually leads them to the utility sector. The industry's relative stability has been highlighted considerably over the past twelve months. Year-to-date, the Value Line Utility Average has remained relatively flat, rising a modest .3%, while the Value Line Geometric Average is down 12.1%.

In this report, we touch on pending merger & acquisition activity among Issue 1 utilities. We also point out some attractive dividend plays for investors seeking income.

Merger/Acquisition Updates

Progress/Duke: *Duke Energy's* $14 billion buyout of rival *Progress Energy* remains scheduled for a late-2011 completion. The combination recently gained regulatory approval in Kentucky but still needs clearance from the commissions in North Carolina and South Carolina. Shareholder votes for both companies were to be held shortly after this issue went to press. As mentioned in previous reports, a successful completion would create the largest electric utility in the United States based on customers served (about 7.1 million).

Northeast/NSTAR: *Northeast Utilities* $4.5 billion acquisition of *NSTAR* appears to be hitting a few speed bumps. Although each company's shareholders and the Federal Energy Regulatory Commission have approved the deal, gaining state approvals appears to be a bit more challenging. Political opposition has raised concerns in Massachusetts, while uncertainty regarding jurisdiction issues in Connecticut has done the same. Even with all of this, the companies remain optimistic that the deal will be completed sometime during the fourth quarter of 2011.

Exelon/Constellation: *Exelon Corp's* $7.9 billion bid to acquire *Constellation Energy* is currently pending. The deal must still be approved by each company's respective shareholders, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, as well as state regulators in Maryland and New York. However, the situation in Maryland has become somewhat worrisome in the early stages, as intervenors are asking for much larger concessions than *Exelon* has agreed to provide. Despite this, the companies are still targeting an early-2012 completion.

Central Vermont/Gaz Metro: *Central Vermont* has entered into a definitive agreement to be acquired by Canadian-based *Gaz Metro Limited* for $35.25 a share, terminating its previous $35.10-a-share agreement with *Fortis Inc.* The offer from *Gaz Metro* represented a 45% premium over CV's closing price prior to the announcement with Fortis. The deal is still subject to regulatory and shareholder approvals.

INDUSTRY TIMELINESS: 38 (of 98)

Dividends

At present, stocks in the Electric Utility industry are yielding 4.4% on average, well above the *Value Line Investment Survey* average (2.3%). Income-oriented investors should have little trouble finding attractive options within the group. In Issue 1, several are currently returning over 5% annually: *Pepco Holdings* (5.7%), *Duke Energy* (5.5%), *Progress Energy* (5.3%), *UIL Holdings* (5.3%), *FirstEnergy* (5.2%), *PPL Corp.* (5.2%), and *SCANA Corp.* (5.1%).

Conclusion

As mentioned earlier, the Value Line Utility Average continues to outperform the Value Line Geometric Average year to date. Due to the weakened economic environment, we believe investors will likely continue to flock to utility stocks in the near term for their relative stability and high dividend yields. That said, it is worth mentioning that the utility industry's positive performance relative to the broader market has raised prices so much that several stocks are not trading within or near their projected 3- to 5-year Target Price Ranges. This often indicates that valuations may be a bit on the high side.

Michael Ratty

Composite Statistics: Electric Utility Industry

2007	2008	2009	2010	2011	2012		14-16
341.6	363.6	321.0	329.2	***320***	***335***	Revenues ($bill)	***385***
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33.1%	33.5%	32.2%	34.2%	***34.5%***	***34.5%***	Income Tax Rate	***34.5%***
6.3%	7.8%	9.2%	8.5%	***7.0%***	***7.0%***	AFUDC % to Net Profit	***6.0%***
50.9%	53.6%	52.4%	52.2%	***51.0%***	***50.5%***	Long-Term Debt Ratio	***50.0%***
48.0%	45.4%	46.6%	47.0%	***48.5%***	***49.0%***	Common Equity Ratio	***49.5%***
467.8	514.0	554.1	585.7	***575***	***605***	Total Capital ($bill)	***695***
505.5	554.4	594.5	640.1	***640***	***680***	Net Plant ($bill)	***780***
7.5%	6.9%	6.5%	6.6%	***6.5%***	***6.5%***	Return on Total Cap'l	***7.0%***
11.9%	11.6%	10.5%	10.7%	***10.0%***	***10.0%***	Return on Shr. Equity	***10.5%***
12.1%	11.8%	10.6%	10.8%	***10.0%***	***10.0%***	Return on Com Equity	***10.5%***
5.5%	4.9%	4.2%	4.5%	***4.0%***	***4.0%***	Retained to Com Eq	***4.5%***
55%	58%	61%	59%	***62%***	***61%***	All Div'ds to Net Prof	***58%***
16.9	15.4	12.5	12.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***13.5***
.90	.93	.83	.82			Relative P/E Ratio	***.90***
3.2%	3.8%	4.8%	4.5%			Avg Ann'l Div'd Yield	***4.3%***

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2008	2009	2010
% Change Retail Sales (kwh)	-1.1	-5.4	+3.6
Average Indust. Use (mwh)	1529	1446	1530
Avg. Indust. Revs. per kwh (¢)	6.66	6.46	6.56
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	+1.6
Fixed Charge Coverage (%)	311	280	305

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

AMEREN NYSE-AEE

RECENT PRICE 29.46 | P/E RATIO 11.7 (Trailing: 11.4 Median: 15.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 5.2% | VALUE LINE

TIMELINESS 3 Raised 8/27/10
SAFETY 3 Lowered 6/26/09
TECHNICAL 3 Lowered 9/2/11
BETA .80 (1.00 = Market)

High:	46.9	46.0	45.3	46.5	50.4	56.8	55.2	55.0	54.3	35.3	29.9	30.5		
Low:	27.6	36.5	34.7	37.4	40.6	47.5	48.0	47.1	25.5	19.5	23.1	25.5		

Target Price Range 2014 | 2015 | 2016

2014-16 PROJECTIONS

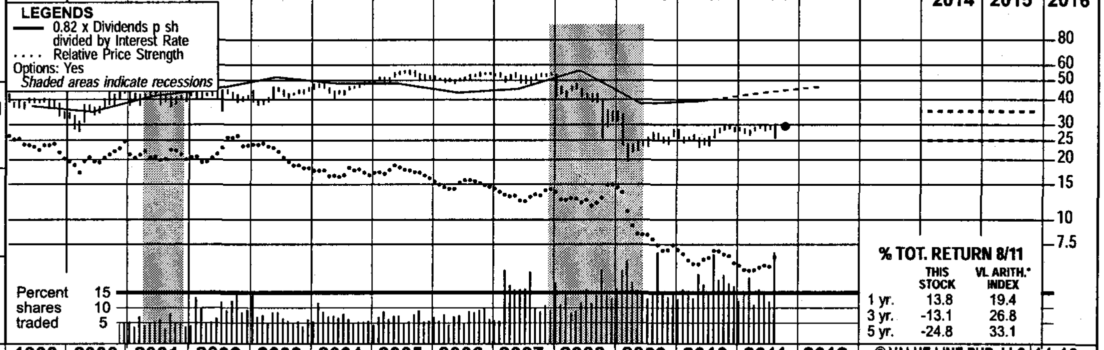
	Price	Gain	Ann'l Total Return
High	35	(+20%)	9%
Low	25	(-15%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	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

	4Q2010	1Q2011	2Q2011
to Buy	179	129	151
to Sell	151	177	152
Hld's(000)	137716	141870	141320



1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
20.59	22.13	24.24	24.18	25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	*31.15*	*31.15*	Revenues per sh	*32.50*
5.14	5.12	4.96	5.36	5.36	6.11	6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	*6.00*	*6.10*	"Cash Flow" per sh	*6.50*
2.95	2.86	2.44	2.82	2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	*2.40*	*2.40*	Earnings per sh A	*2.50*
2.46	2.51	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	*1.54*	*1.54*	Div'd Decl'd per sh B■†	*1.54*
3.05	3.18	2.77	2.37	4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	*4.80*	*5.25*	Cap'l Spending per sh	*5.75*
22.71	23.06	22.00	22.27	22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	*32.65*	*33.45*	Book Value per sh C	*36.00*
102.12	102.12	137.22	137.22	137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	*244.00*	*247.00*	Common Shs Outst'g D	*256.00*
12.6	13.8	15.5	14.2	13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.84	.86	.89	.74	.77	.72	.62	.86	.77	.86	.89	1.05	.92	.85	.62	.62	*Value Line*		Relative P/E Ratio	*.85*
6.6%	6.3%	6.7%	6.3%	6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $7396.0 mill. Due in 5 Yrs $1538.0 mill.
LT Debt $7054.0 mill. LT Interest $455.0 mill.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $39.0 mill.
Pension Assets-12/10 $2.72 bill. Oblig. $3.45 bill.
Pfd Stock $142.0 mill. Pfd Div'd $8.0 mill.
807,595 shs. $3.50 to $5.50 cum. (no par), $100 stated value, redeemable at $102.176-$110/sh.; 616,323 shs. 4.00% to 6.625%, $100 par, redeemable at $100-$104/sh.
Common Stock 241,148,657 shs. as of 4/29/11
MARKET CAP: $7.1 billion (Large Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
4505.9	3841.0	4593.0	5160.0	6780.0	6880.0	7546.0	7839.0	7090.0	7638.0	*7600*	*7700*	Revenues ($mill)	*8300*
481.0	393.0	517.0	541.0	628.0	547.0	629.0	615.0	624.0	669.0	*590*	*600*	Net Profit ($mill)	*650*
38.4%	38.9%	36.8%	34.3%	35.6%	32.7%	33.5%	33.7%	34.7%	36.8%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
4.3%	2.8%	1.9%	1.8%	2.9%	.7%	.8%	4.6%	5.8%	7.8%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*7.0%*
44.2%	46.0%	47.3%	45.5%	44.9%	43.8%	45.0%	47.8%	49.7%	48.2%	*47.0%*	*46.0%*	Long-Term Debt Ratio	*45.5%*
52.2%	51.4%	50.6%	52.6%	53.3%	54.6%	53.4%	50.8%	49.1%	50.9%	*52.5%*	*53.0%*	Common Equity Ratio	*53.5%*
6419.3	7468.0	8606.0	11036	11932	12063	12654	13712	15991	15185	*15250*	*15650*	Total Capital ($mill)	*17200*
8426.6	8914.0	10917	13297	13572	14286	15069	16567	17610	17853	*18125*	*18525*	Net Plant ($mill)	*19800*
8.7%	6.5%	7.4%	6.0%	6.5%	5.7%	6.2%	5.7%	5.3%	6.0%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
13.4%	9.7%	11.4%	9.0%	9.5%	8.1%	9.0%	8.6%	7.8%	8.5%	*7.0%*	*7.0%*	Return on Shr. Equity	*7.0%*
14.0%	9.9%	11.6%	9.1%	9.7%	8.1%	9.2%	8.7%	7.8%	8.6%	*7.0%*	*7.0%*	Return on Com Equity E	*7.0%*
3.6%	.2%	2.2%	.9%	1.7%	.2%	1.3%	1.0%	3.5%	3.8%	*2.5%*	*2.5%*	Retained to Com Eq	*2.5%*
75%	98%	81%	91%	83%	97%	86%	88%	56%	56%	*64%*	*65%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.6	-4.1	+8.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.43	4.45	4.63
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	296	266	293

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	2.5%	2.5%	*Nil*
"Cash Flow"	1.0%	1.0%	*.5%*
Earnings	-.5%	-1.5%	*-2.0%*
Dividends	-3.0%	-6.0%	*-3.0%*
Book Value	3.5%	2.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	2081	1790	2060	1908	7839.0
2009	1916	1684	1815	1675	7090.0
2010	1940	1725	2267	1706	7638.0
2011	1904	1781	*2150*	*1765*	*7600*
2012	*1950*	*1800*	*2150*	*1800*	*7700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.66	.98	.97	.27	2.88
2009	.66	.77	1.04	.34	2.78
2010	.43	.64	1.49	.21	2.77
2011	.29	.57	*1.24*	*.30*	*2.40*
2012	*.40*	*.60*	*1.10*	*.30*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.635	.635	.635	.635	2.54
2008	.635	.635	.635	.635	2.54
2009	.385	.385	.385	.385	1.54
2010	.385	.385	.385	.385	1.54
2011	.385	.385			

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 1/03; Illinois Power 10/04. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 811,000 gas customers in Illinois. Electric revenue breakdown: residential, 48%; commercial, 31%; industrial, 10%; other, 11%. Generating sources: coal, 66%; nuclear, 9%; hydro, 2%; gas, 1%; purchased, 22%. Fuel costs: 41% of revenues. '10 reported depreciation rates: 3%-4%. Has 9,800 employees. Chairman, President & CEO: Thomas R. Voss. Incorporated: Missouri. Address: One Ameren Plaza, 1901 Chouteau Avenue, P.O. Box 66149, St. Louis, Missouri 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren has received an electric rate increase in Missouri. The state commission granted the utility a tariff hike of $173 million, based on a 10.2% return on a 52.2% common-equity ratio. Disappointingly, $89 million of capital investment was disallowed. Ameren has appealed this to the state Court of Appeals. (This will cause a nonrecurring charge, estimated at $0.23 a share, in the third quarter.) New rates took effect at the end of July.

Electric and gas rate requests are pending in Illinois. Ameren is seeking an electric hike of $39 million, based on an 11% return on equity, and a gas increase of $50 million, based on a 10.75% ROE. The requested common-equity ratio is 52.87%. The staff of the Illinois Commerce Commission (ICC) is recommending a total (electric and gas) increase of $31 million, and the state attorney general and Citizens Utility Board are proposing a total *decrease* of $2 million. The ICC's order is due in January, with new rates taking effect shortly thereafter.

Earnings are probably headed down this year. An unusually large number of storms hurt profits in the first half of 2011. Kilowatt-hour sales were running lower than expected, until an unusually hot summer offset this somewhat. Margins are under pressure at Ameren's merchant generation subsidiary, due to weak power prices and rising coal costs. Our 2011 share-net estimate of $2.40 is within Ameren's guidance of $2.30-$2.55.

We look for flat earnings in 2012. We figure that improvement at the utility operations (thanks largely to rate relief) will offset another decline in income at the nonregulated side of the business.

Ameren has announced its strategy for dealing with more stringent EPA rules for coal plants. The company will reduce its capital budget by $700 million by switching to lower-sulfur coal. This will increase its operating expenses, however.

We do not recommend this stock. The dividend is above the utility average, but by less than a percentage point. In our view, this is not enough to compensate investors for a lack of dividend growth potential. With the stock trading near the middle of our 2014-2016 Target Price Range, total return potential is unexciting.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted EPS. Excl. nonrecur. gain (losses): '03, 11¢; '05, (11¢); '10, ($2.19); 3Q '11, (23¢). '09 EPS don't add due to change in shs. Next earnings report due early Nov. (B) Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '10: $6.98/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in MO in '10: 10.1%; in IL in '10: 9.9%-10.3% electric, 9.2%-9.4% gas; earned on avg. com. eq., '10: 8.2%. Regul. Clim.: MO, Average; IL, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	90

AMERICAN ELEC. PWR. NYSE-AEP

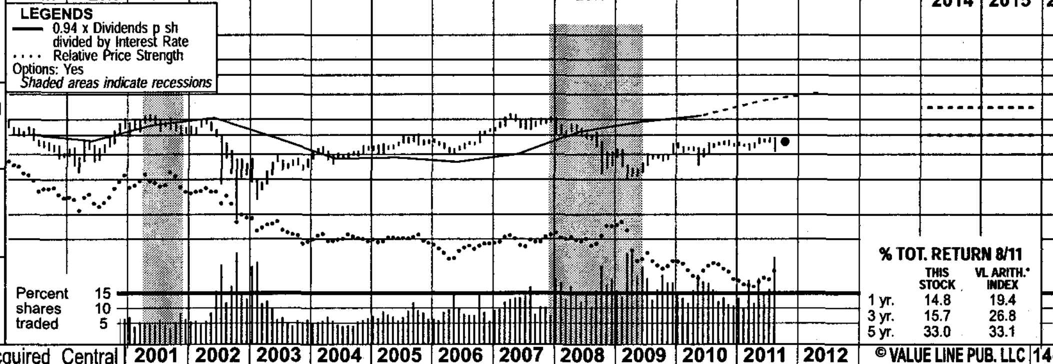
RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
37.13	11.5 (Trailing: 12.0; Median: 13.0)	0.86	5.1%

VALUE LINE

TIMELINESS 2 Raised 8/19/11
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Lowered 9/16/11
BETA .70 (1.00 = Market)

High:	48.9	51.2	48.8	31.5	35.5	40.8	43.1	51.2	49.1	36.5	37.9	39.0
Low:	25.9	39.3	15.1	19.0	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+50%)	14%
Low	40	(+10%)	7%

Insider Decisions

	O	N	D	J	F	M	A	M	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	0	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	241	235	236
to Sell	229	236	233
Hld's(000)	316321	315480	318229

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.8	19.4
3 yr.	15.7	26.8
5 yr.	33.0	33.1

American Electric Power acquired Central and South West Corporation (CSW) in 2000. CSW common stockholders received 0.6 of an AEP common share for each of their shares, for a total of $4.5 billion. The transaction was effected under pooling-of-interests accounting rules.

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	**31.55**	**33.15**	Revenues per sh	**39.00**
7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	**6.70**	**6.95**	"Cash Flow" per sh	**8.00**
3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	**3.15**	**3.25**	Earnings per sh A	**3.75**
2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	**1.84**	**1.90**	Div'd Decl'd per sh B ■	**2.10**
5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	**5.75**	**6.30**	Cap'l Spending per sh	**7.00**
25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	**29.60**	**31.05**	Book Value per sh C	**36.00**
322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	**485.00**	**489.00**	Common Shs Outst'g D	**500.00**
13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**12.5**
.71	.69	.61	.66	.73	.70	.87	.79	.67	.86			Relative P/E Ratio	**.85**
5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%			Avg Ann'l Div'd Yield	**4.5%**
61257	14555	14545	14057	12111	12622	13380	14440	13489	14427	**15300**	**16200**	Revenues ($mill)	**19500**
1063.0	976.0	984.0	1038.0	1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	**1520**	**1590**	Net Profit ($mill)	**1910**
36.0%	25.2%	38.8%	33.1%	29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
--	--	3.8%	3.6%	5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	**11.0%**	**11.0%**	AFUDC % to Net Profit	**10.0%**
54.6%	56.0%	60.6%	56.2%	54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	**52.0%**	**51.5%**	Long-Term Debt Ratio	**49.5%**
44.6%	43.1%	38.7%	43.1%	44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	**47.5%**	**48.5%**	Common Equity Ratio	**50.5%**
18459	16393	20333	19584	20222	21902	24342	26290	28958	29184	**30150**	**31450**	Total Capital ($mill)	**35800**
24543	21684	22029	22801	24284	26781	29870	32987	34344	35674	**36725**	**38000**	Net Plant ($mill)	**41800**
7.5%	7.5%	6.6%	7.0%	6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	**6.5%**	**6.5%**	Return on Total Cap'l	**7.0%**
12.7%	13.5%	12.3%	12.1%	11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	**10.5%**	**10.5%**	Return on Shr. Equity	**10.5%**
12.8%	13.7%	12.4%	12.2%	11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	**10.5%**	**10.5%**	Return on Com Equity E	**10.5%**
3.4%	2.4%	4.5%	5.7%	5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	**4.5%**	**4.5%**	Retained to Com Eq	**5.0%**
74%	82%	64%	54%	54%	53%	55%	55%	56%	66%	**59%**	**58%**	All Div'ds to Net Prof	**55%**

CAPITAL STRUCTURE as of 6/30/11
Total Debt $18274 mill. **Due in 5 Yrs** $7332 mill.
LT Debt $15564 mill. **LT Interest** $856 mill.
Incl. $1703 mill. securitized bonds.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $306 mill.

Pension Assets-12/10 $3.86 bill. **Oblig.** $4.81 bill.

Pfd Stock $61 mill. **Pfd Div'd** $3 mill.
607,044 shs. 4%-5%, cumulative, callable at $102-$110.

Common Stock 482,273,829 shs. as of 7/28/11

MARKET CAP: $18 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-.1	-6.4	+4.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.08	4.83	4.95
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	244	265	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-1.5%	-2.0%	4.0%
"Cash Flow"	1.0%	2.0%	3.5%
Earnings	2.5%	2.0%	4.5%
Dividends	-3.5%	2.0%	4.0%
Book Value	1.0%	5.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	3467	3546	4191	3236	14440
2009	3458	3202	3547	3282	13489
2010	3569	3360	4064	3434	14427
2011	3730	3609	**4311**	**3650**	**15300**
2012	**3900**	**3900**	**4500**	**3900**	**16200**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.02	.70	.93	.34	2.99
2009	.89	.68	.93	.49	2.97
2010	.72	.35	1.16	.37	2.60
2011	.83	.73	**1.14**	**.45**	**3.15**
2012	**.90**	**.80**	**1.10**	**.45**	**3.25**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.39	.39	.39	.41	1.58
2008	.41	.41	.41	.41	1.64
2009	.41	.41	.41	.41	1.64
2010	.41	.42	.42	.46	1.71
2011	.46	.46	.46		

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves about 5.3 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown: residential, 37%; commercial, 25%; industrial, 21%; wholesale, 14%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 35% of revenues. '10 deprec. rate: 3.3%. Has 18,700 employees. Chairman & CEO: Michael G. Morris. President: Nicholas K. Akins. Inc.: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power is facing significant upgrades and asset retirements stemming from new EPA rules affecting coal-fired generating plants. In early June, AEP announced its expected compliance plan, which called for spending $6 billion-$8 billion through the end of the decade. The company would upgrade some plants, retire nearly 6,000 megawatts of capacity, convert 1,070 mw of coal-fired units to use gas, and construct 1,220 mw of gas-fired generation. Most of these expenditures would be recoverable in customers' rates, depending upon what happens in Ohio (see below). AEP won't finalize its plans until after the EPA issues a rule in November dealing with mercury emissions. Until the company's plans are set, our capital spending estimates and projections won't reflect the new spending.

AEP has reached a regulatory settlement for generation in Ohio. The agreement, which has some opposition and must still be approved by the Public Utilities Commission, calls for a gradual transition to market prices by 2015, with AEP's generating plants being transferred to a nonutility subsidiary. This should mitigate the adverse effects of customer choice of energy suppliers, which is hurting owners of generating plants in Ohio.

Earnings should advance significantly in 2011, followed by a much smaller increase in 2012. The June-quarter comparison was easy because the cost of a restructuring program lowered share net by $0.39 in 2010. Ongoing rate relief is another plus for the bottom line. We raised our 2011 profit estimate by $0.05 a share due to an unusually hot summer. Our revised estimate remains within AEP's earnings target of $3.00-$3.20 a share. Our 2012 forecast is still $3.25 a share.

AEP is expecting a sizable payment in Texas. A state Supreme Court ruling will enable the company to recoup $420 million that was denied by the state commission in 2006. With interest, the payment might be more than double this amount. AEP plans to use the cash for debt retirement and capital spending.

This timely stock has some appeal for utility investors. The yield is above the mean for electric companies, as is its 3- to 5-year total return potential.

Paul E. Debbas, CFA *September 23, 2011*

(A) Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, (10¢); gains (losses) on disc. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '09, (1¢). '09 EPS don't add due to change in shs. Next egs. due late Oct. (B) Div'ds historically paid early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '10: $16.31/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.96%-15.7%; earned on avg. com. eq., '10: 9.3%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	90

CENTERPOINT EN'RGY NYSE-CNP

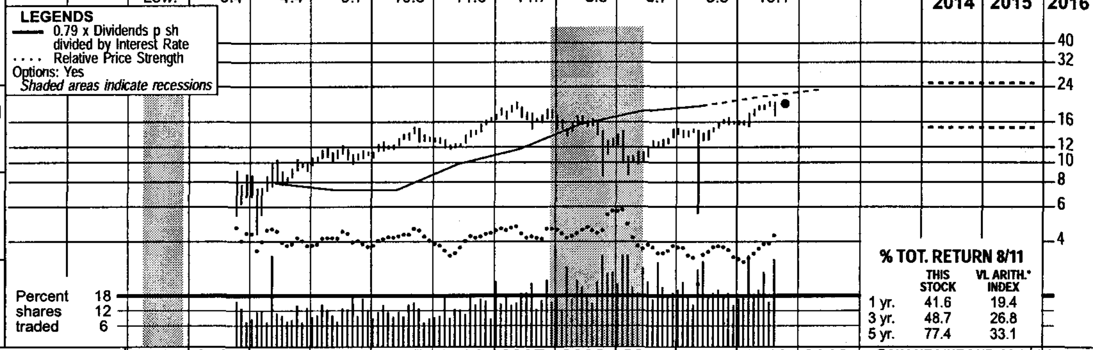
RECENT PRICE 19.83 | P/E RATIO 16.9 (Trailing: 16.4 / Median: NMF) | RELATIVE P/E RATIO 1.26 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 2 Raised 5/13/11
SAFETY 3 Raised 3/31/06
TECHNICAL 2 Raised 9/9/11
BETA .80 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	9.2	10.5	12.3	15.1	16.9	20.2	17.3	14.9	17.0	20.4
Low:	5.4	4.4	9.7	10.5	11.6	14.7	8.5	8.7	5.5	15.1

Target Price Range 2014 | 2015 | 2016

LEGENDS
— 0.79 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+25%)	9%
Low	15	(-25%)	-2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	1	0	0	0
Options	0	2	0	0	0	1	0	2	0
to Sell	0	3	0	0	0	1	0	3	1

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	168	151	174
to Sell	159	174	165
Hld's(000)	293850	297873	297292

Percent shares traded 18 12 6

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	41.6	19.4
3 yr.	48.7	26.8
5 yr.	77.4	33.1

CenterPoint Energy owns the utility operations that were part of Reliant Energy. The stock began trading on the New York Stock Exchange on Oct. 1, 2002, a day after Reliant Energy spun off its 83% interest in Reliant Resources, which has been renamed RRI Energy (NYSE: RRI). On Jan. 6, 2003, CenterPoint completed the distribution to its shareholders of a 19% interest in Texas Genco Holdings, which owns generating assets in Texas. CenterPoint reacquired the publicly traded stock on Dec. 14, 2004 as the first step of a sale of Texas Genco.

2001A	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
35.18	26.40	31.87	27.63	31.33	29.71	29.82	32.71	21.14	20.69	*19.70*	*19.65*	Revenues per sh	*21.75*
3.69	3.34	3.98	2.56	2.72	3.47	3.39	3.42	2.94	3.14	*3.45*	*3.60*	"Cash Flow" per sh	*4.25*
1.54	1.29	1.37	.61	.67	1.33	1.17	1.30	1.01	1.07	*1.20*	*1.20*	Earnings per sh B	*1.35*
1.50	1.07	.40	.40	.40	.60	.68	.73	.76	.78	*.79*	*.80*	Div'd Decl'd per sh C ■ †	*.90*
6.78	2.85	2.11	1.72	2.23	3.21	3.45	2.95	2.96	3.55	*3.15*	*2.45*	Cap'l Spending per sh	*2.00*
22.24	4.74	5.75	3.59	4.18	4.96	5.61	5.89	6.74	7.53	*9.90*	*10.35*	Book Value per sh D	*12.00*
302.94	300.10	306.30	308.05	310.33	313.65	322.72	346.09	391.75	424.70	*426.00*	*427.00*	Common Shs Outst'g E	*430.00*
--	5.6	6.0	17.8	19.1	10.3	15.0	11.3	11.8	13.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	.31	.34	.94	1.02	.56	.80	.68	.79	.88	*Value Line*		Relative P/E Ratio	*.95*
--	14.8%	4.8%	3.7%	3.1%	4.4%	3.9%	5.0%	6.4%	5.3%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*
10656	7922.5	9760.1	8510.4	9722.0	9319.0	9623.0	11322	8281.0	8785.0	*8400*	*8400*	Revenues ($mill)	*9350*
446.9	386.3	419.7	205.7	225.0	432.0	399.0	447.0	372.0	442.0	*515*	*520*	Net Profit ($mill)	*600*
33.8%	35.0%	32.5%	40.2%	40.5%	12.6%	32.8%	38.3%	32.1%	37.3%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
2.0%	3.1%	3.1%	1.9%	1.8%	2.3%	5.5%	2.7%	1.3%	2.7%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
45.5%	87.4%	86.0%	86.7%	86.9%	83.4%	82.2%	83.3%	77.6%	73.8%	*72.0%*	*68.5%*	Long-Term Debt Ratio	*68.5%*
54.5%	12.6%	14.0%	13.3%	13.1%	16.6%	17.8%	16.7%	22.4%	26.2%	*28.0%*	*31.5%*	Common Equity Ratio	*31.5%*
12363	11322	12544	8298.5	9864.0	9358.0	10174	12218	11758	12199	*15025*	*14075*	Total Capital ($mill)	*16200*
11200	11409	11812	8186.4	8492.0	9204.0	9740.0	10296	10788	11732	*12175*	*12250*	Net Plant ($mill)	*11900*
5.2%	6.6%	6.5%	6.8%	5.3%	7.8%	6.9%	6.0%	5.8%	6.1%	*5.5%*	*6.0%*	Return on Total Cap'l	*5.5%*
6.6%	27.2%	23.8%	18.6%	17.4%	27.8%	22.0%	21.9%	14.1%	13.8%	*12.0%*	*12.0%*	Return on Shr. Equity	*11.5%*
6.6%	27.2%	23.8%	18.6%	17.4%	27.8%	22.0%	21.9%	14.1%	13.8%	*12.0%*	*12.0%*	Return on Com Equity F	*11.5%*
.2%	4.3%	16.0%	7.5%	7.8%	15.7%	10.0%	9.9%	3.6%	3.8%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
97%	84%	33%	60%	55%	43%	55%	55%	74%	72%	*66%*	*66%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $9087.0 mill. **Due in 5 Yrs** $4154.0 mill.
LT Debt $8510.0 mill. **LT Interest** $511.0 mill.
Incl. $2371.0 mill. transition & system restoration bonds.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $15.0 mill.
Pension Assets-12/10 $1.50 bill. **Oblig.** $1.97 bill.
Pfd Stock None
Common Stock 425,856,294 shs. **as of 7/15/11**
MARKET CAP: $8.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.9	-.3	+3.2
Avg. Indust. Use (MWH)	NA	NA	NA
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 (%)	NA	NA	NA
% Change Customers (avg.)	+1.5	+1.4	+1.3
Fixed Charge Cov. (%)	207	173	197

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	-4.0%	-2.0%
"Cash Flow"	--	.5%	5.0%
Earnings	--	5.0%	3.0%
Dividends	--	13.5%	3.0%
Book Value	--	8.5%	10.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2008	3363	2670	2515	2774	11322
2009	2766	1640	1576	2299	8281.0
2010	3023	1756	1908	2098	8785.0
2011	2587	1837	*1976*	*2000*	*8400*
2012	*2700*	*1750*	*1850*	*2100*	*8400*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2008	.36	.30	.39	.25	1.30
2009	.19	.24	.31	.27	1.01
2010	.29	.20	.29	.29	1.07
2011	.35	.28	*.29*	*.28*	*1.20*
2012	*.32*	*.26*	*.31*	*.31*	*1.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.17	.17	.17	.17	.68
2008	.1825	.1825	.1825	.1825	.73
2009	.19	.19	.19	.19	.76
2010	.195	.195	.195	.195	.78
2011	.1975	.1975	.1975		

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.1 million customers in Houston and environs, and gas utilities with 3.3 million customers: Entex (Texas, Louisiana, Mississippi); Arkla (Arkansas, Louisiana, Oklahoma, Texas); and Minnegasco (Minnesota). Has gas pipeline and storage assets. Discont. Texas Genco Holdings in '04. Electric rev. breakdown: residential, 52%; commercial, 31%; industrial, 15%; other, 2%. Does not own generating assets. Natural gas costs: 52% of revs. '10 deprec. rate: 5.6%. Has 8,800 employees. Chairman: Milton Carroll. President & CEO: David M. McClanahan. Inc.: TX. Address: 1111 Louisiana, P.O. Box 4567, Houston, TX 77210-4567. Tel.: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy is awaiting the resolution of a long-running regulatory matter. This dates back to a $947 million aftertax charge that the company took in 2004, after the Public Utility Commission of Texas (PUCT) disallowed some costs associated with the utility's generating assets. CenterPoint appealed the order and was ultimately successful. The state Supreme Court remanded the case back to the PUCT so that CenterPoint could recoup the monies that were disallowed, plus interest. The utility will ask the PUCT for permission to recover the money through the issuance of securitized bonds. CenterPoint and various intervenors are arguing over what is recoverable, but the company will wind up with a large sum of money—roughly $1.1 billion after taxes, if it prevails. CenterPoint's priority is to use the cash to expand its business through capital investments or acquisitions. Debt retirement and a stock buyback are likely, too. It appears as if this matter will not be resolved until October, at the earliest.

We have raised our 2011 earnings estimate by $0.05 a share, to $1.20. Second-quarter profits were above our expectation, due *in* part to warmer-than-normal weather patterns. Our 2012 forecast is based on normal weather. One factor that will hurt results is a negative electric rate ruling, which CenterPoint has appealed to the state district court, that took effect at the start of September. The order will reduce operating income by $10 million this year and $30 million annually.

CenterPoint is looking to expand its Field Services operation. This division is benefiting from projects that went into service in the past year. Its operating income rose 39% in the first half of 2011.

This timely stock has been one of the top-performing utility issues so far this year, having risen 26% to date. This is largely due to investors' enthusiasm about the favorable verdict from the Texas Supreme Court. We believe there is also some takeover speculation reflected in the share price. Following the stock's run-up, the dividend yield is not exceptional for a utility, and with the quotation now in the middle of our 2014-2016 Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *September 23, 2011*

(A) Pro forma data. (B) Diluted EPS. Excl. extraordinary gains (loss): '04, ($2.72); '05, 9¢; '11, *$1.94*; gain (losses) on discont. ops.: '03, 2¢; '04, (37¢); '05, (1¢). Next earnings report due early Nov. (C) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (D) Incl. intangibles. In '10: $12.10/sh. (E) In mill. (F) Rate base: Net orig. cost. Rate allowed on com. eq. (elec.) in '11: 10%; (gas): 9.45%-11.25%; earned on avg. com. eq., '10: 15.1%. Regulatory Climate: Average.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	65

CLECO CORPORATION NYSE-CNL

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
34.63	14.9 (Trailing: 16.0; Median: 14.0)	1.11	3.4%	

TIMELINESS 3 Lowered 2/11/11
SAFETY 2 Raised 6/24/11
TECHNICAL 3 Raised 6/10/11
BETA .65 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+15%)	7%
Low	30	(-15%)	1%

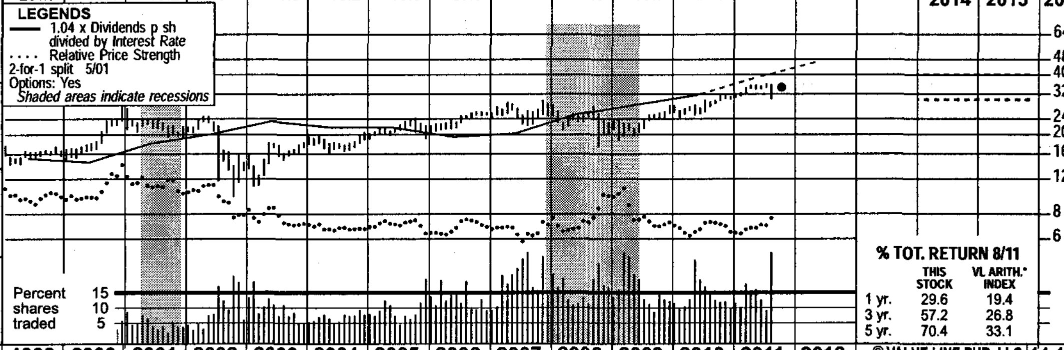
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	2	0	0	0
Options	0	4	0	0	0	2	0	0	1
to Sell	0	4	0	0	0	3	0	2	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	79	85	73
to Sell	79	80	94
Hld's(000)	44280	44515	44773

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	28.3	27.3	24.9	18.4	20.8	24.4	26.2	29.8	28.4	28.1	31.8	36.1
Low:	15.1	19.2	9.7	11.0	16.2	18.9	20.5	22.1	17.3	18.7	24.3	30.1



Target Price Range

2014	2015	2016

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.6	19.4
3 yr.	57.2	26.8
5 yr.	70.4	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
8.79	9.70	10.16	11.46	17.12	18.23	23.55	15.33	18.54	15.03	18.41	17.38	17.19	17.99	14.17	18.98	*19.30*	*19.75*	Revenues per sh	*22.25*
1.99	2.11	2.18	2.28	2.36	2.77	2.94	3.05	2.98	2.56	2.76	2.63	2.69	3.71	3.78	5.12	*5.65*	*5.80*	"Cash Flow" per sh	*6.50*
1.04	1.12	1.09	1.12	1.19	1.46	1.51	1.52	1.26	1.32	1.42	1.36	1.32	1.70	1.76	2.29	*2.40*	*2.40*	Earnings per sh A	*2.75*
.75	.77	.79	.81	.83	.85	.87	.90	.90	.90	.90	.90	.90	.90	.90	.98	*1.09*	*1.22*	Div'd Decl'd per sh B ■ †	*1.60*
1.29	1.43	1.73	2.09	3.99	2.52	1.10	1.91	1.58	1.61	3.19	4.11	8.51	5.59	4.15	4.68	*4.15*	*3.60*	Cap'l Spending per sh	*4.00*
7.91	8.30	8.68	9.07	9.44	10.04	10.69	11.77	10.09	10.83	13.69	15.22	16.85	17.65	18.50	21.76	*23.65*	*24.90*	Book Value per sh C	*28.50*
44.85	44.91	44.93	44.97	44.88	44.99	44.96	47.04	47.18	49.62	49.99	57.57	59.94	60.04	60.26	60.53	*60.70*	*60.70*	Common Shs Outst'g D	*60.70*
11.6	11.9	12.5	14.4	13.4	13.2	14.6	12.2	12.4	13.8	15.0	17.3	19.6	14.1	13.2	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.78	.75	.72	.75	.76	.86	.75	.67	.71	.73	.80	.93	1.04	.85	.88	.79	*Value Line*		Relative P/E Ratio	*.85*
6.2%	5.8%	5.8%	5.0%	5.2%	4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	3.5%	3.8%	3.9%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $1400.0 mill. **Due in 5 Yrs** $230.2 mill.
LT Debt $1387.3 mill. **LT Interest** $84.6 mill.
Incl. $17.5 million capitalized leases.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $9.2 mill.
Pension Assets-12/10 $242.5 mill.
Oblig. $330.3 mill.

Pfd Stock None

Common Stock 61,062,449 shs.
as of 7/29/11
MARKET CAP: $2.1 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
1058.6	721.2	874.6	745.8	920.2	1000.7	1030.6	1080.2	853.8	1148.7	*1170*	*1200*	Revenues ($mill)	*1350*
72.3	74.2	61.2	66.1	75.0	74.7	79.6	102.1	106.3	139.5	*145*	*150*	Net Profit ($mill)	*170*
34.7%	36.9%	37.2%	35.2%	39.2%	36.0%	24.3%	15.3%	8.3%	44.1%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
16.7%	12.6%	5.8%	7.5%	4.3%	14.2%	57.9%	82.8%	93.5%	12.2%	*7.0%*	*5.0%*	AFUDC % to Net Profit	*3.0%*
55.2%	60.0%	64.4%	44.5%	46.3%	40.9%	43.2%	51.1%	54.2%	51.5%	*46.5%*	*45.5%*	Long-Term Debt Ratio	*42.0%*
42.4%	38.2%	33.8%	53.1%	52.0%	57.8%	56.7%	48.9%	45.8%	48.5%	*53.5%*	*54.5%*	Common Equity Ratio	*58.0%*
1134.7	1448.7	1408.5	1011.6	1315.9	1515.6	1780.5	2167.7	2436.4	2717.9	*2685*	*2760*	Total Capital ($mill)	*2975*
1224.7	1566.2	1417.1	1060.0	1188.7	1304.9	1725.9	2045.3	2247.0	2784.2	*2840*	*2855*	Net Plant ($mill)	*2875*
8.6%	7.1%	6.7%	8.9%	7.1%	6.3%	5.6%	6.1%	5.9%	6.6%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
14.2%	12.8%	12.2%	11.8%	10.6%	8.3%	7.9%	9.6%	9.5%	10.6%	*10.0%*	*10.0%*	Return on Shr. Equity	*9.5%*
14.6%	13.1%	12.5%	11.9%	10.7%	8.3%	7.8%	9.6%	9.5%	10.6%	*10.0%*	*10.0%*	Return on Com Equity E	*9.5%*
6.5%	5.6%	3.5%	3.9%	4.1%	3.0%	2.6%	4.5%	4.7%	6.1%	*5.5%*	*5.0%*	Retained to Com Eq	*4.0%*
57%	58%	72%	68%	62%	65%	68%	53%	51%	42%	*45%*	*50%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.1	-6.0	+5.9
Avg. Indust. Use (MWH)	4535	3532	3657
Avg. Indust. Revs. per KWH (¢)	7.89	6.48	7.68
Capacity at Peak (Mw)	2254	2355	NA
Peak Load, Summer (Mw)	2113	2242	2348
Annual Load Factor (%)	57.0	53.5	55.8
% Change Customers (avg.)	+.9	+.7	+.7
Fixed Charge Cov. (%)	159	138	294

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	1.0%	-.5%	*4.5%*
"Cash Flow"	5.5%	8.5%	*7.5%*
Earnings	4.5%	7.5%	*6.0%*
Dividends	1.0%	.5%	*9.5%*
Book Value	7.5%	11.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	222.5	274.8	343.7	239.2	1080.2
2009	213.0	207.2	241.5	192.1	853.8
2010	272.3	275.9	343.9	256.6	1148.7
2011	253.7	272.9	*370*	*273.4*	*1170*
2012	*270*	*280*	*370*	*280*	*1200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.37	.49	.62	.22	1.70
2009	.11	.45	.99	.21	1.76
2010	.56	.58	.82	.33	2.29
2011	.48	.52	*1.10*	*.30*	*2.40*
2012	*.40*	*.60*	*1.10*	*.30*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.225	.225	.225	.225	.90
2008	.225	.225	.225	.225	.90
2009	.225	.225	.225	.225	.90
2010	.225	.25	.25	.25	.98
2011	.25	.28	.28		

BUSINESS: Cleco Corporation is a holding company for Cleco Power, which supplies electricity to about 279,000 customers in central Louisiana. Through a subsidiary, has 775 megawatts of wholesale capacity. Electric revenue breakdown: residential, 45%; commercial, 27%; industrial, 14%; other, 14%. Largest industrial customers are paper mills and other wood-product industries. Generating sources: gas & oil, 30%; coal & lignite, 29%; petroleum coke, 16%; purchased, 25%. Fuel costs: 44% of revenues. '10 reported deprec. rate (utility): 2.6%. Has 1,300 employees. Chairman: J. Patrick Garrett. President & CEO: Bruce A. Williamson. Inc.: Louisiana. Address: 2030 Donahue Ferry Road, P.O. Box 5000, Pineville, LA 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

We estimate that Cleco Corporation's earnings will rise at a mid-single-digit pace in 2011. Cleco Power, the company's regulated utility subsidiary, is benefiting from a regulatory plan that allows it a return on equity of 11.7%, with a chance to earn up to a 12.3% ROE, thanks to incentive ratemaking. We have raised our 2011 earnings estimate by $0.05 a share, to $2.40, due to hotter-than-usual summer weather conditions. That's the upper end of management's targeted range of $2.30-$2.40 a share, which was based on normal weather. **We now look for flat earnings in 2012,** based on our assumption of a return to normal weather patterns.

Dividend growth potential is high. After several years in which the board of directors did not raise the disbursement, it lifted the payout in 2010. Earlier this year, the board boosted the quarterly dividend by $0.03 a share (12%), and Cleco has already stated that an increase of $0.03125 a share (11.1%) is in the offing for 2012.

The company completed an asset sale in the second quarter. Cleco sold its 50% stake in Acadia Unit 2, a gas-fired plant, for $150 million. It used the proceeds for debt reduction. The company recorded a gain of $0.63 a share on the sale, which we excluded from our presentation as a nonrecurring item.

Cleco is still deciding what to do with the Coughlin plant. This 775-megawatt gas-fired facility is the company's sole remaining nonregulated generating asset. Its capacity will be available at the start of 2012, after a contract expires. New EPA rules that will increase costs for coal-fired units might well make Coughlin a more valuable asset.

Two capital projects are under way. Cleco has a 50% stake in a $250 million transmission project. This should be complete by the summer of 2012. The utility is spending $73 million (including a $20 million grant from the federal government) on an advanced metering system. This should be finished by 2013.

This stock does not stand out for the short or long term. The yield is about a percentage point below the utility mean, and 3- to 5-year total return potential is unexciting, despite the good dividend growth prospects mentioned above.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted earnings. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; '07, $1.22; '10, $1.91; 2Q '11, 63¢; losses from disc. ops.: '00, 14¢; '01, 4¢. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '10: $10.51/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '09: 11.7%; earned on avg. com. eq., '10: 11.9%. Regul. Climate: Avg.

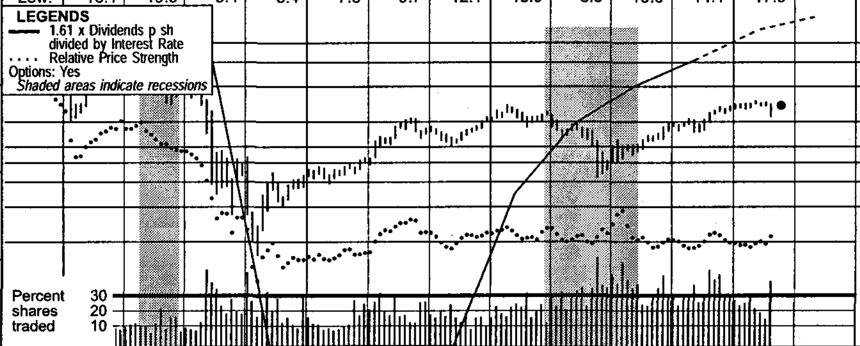
Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	75

CMS ENERGY CORP. NYSE-CMS

RECENT PRICE	19.39	P/E RATIO	13.5 (Trailing: 12.8 / Median: 17.0)	RELATIVE P/E RATIO	1.01	DIV'D YLD	4.6%	VALUE LINE

TIMELINESS 3 Lowered 8/12/11	High:	32.3	31.8	24.8	10.7	10.6	16.8	17.0	19.5	17.5	16.1	19.3	20.5		Target Price Range
SAFETY 3 Raised 12/29/06	Low:	16.1	19.5	5.4	3.4	7.8	9.7	12.1	15.0	8.3	10.0	14.1	17.0		2014 | 2015 | 2016
TECHNICAL 3 Lowered 9/16/11															
BETA .75 (1.00 = Market)															

LEGENDS
— 1.61 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+30%)	11%
Low	18	(-5%)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	1	0
to Sell	0	1	0	0	0	1	0	3	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	147	142	162
to Sell	153	149	132
Hld's(000)	233569	236444	236182

Percent shares traded 30 / 20 / 10

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.6	19.4
3 yr.	63.9	26.8
5 yr.	56.6	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
42.47	45.70	47.49	47.56	52.59	74.24	72.16	60.28	34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	*26.20*	*27.15*	Revenues per sh	*30.00*
6.77	7.18	7.39	6.60	7.87	7.61	5.24	d.09	2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	*3.70*	*3.85*	"Cash Flow" per sh	*4.50*
2.27	2.45	2.61	2.24	2.85	2.53	1.27	d2.99	d.29	.74	1.10	.64	.64	1.23	.93	1.33	*1.45*	*1.55*	Earnings per sh A	*1.75*
.90	1.02	1.14	1.26	1.39	1.46	1.46	1.09	--	--	--	--	.20	.36	.50	.66	*.84*	*.92*	Div'd Decl'd per sh B ■	*1.10*
5.84	6.95	7.05	11.98	9.69	8.51	9.49	5.18	3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	*4.25*	*5.10*	Cap'l Spending per sh	*4.75*
16.04	17.95	19.61	20.63	21.17	19.48	14.21	7.86	9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	*12.00*	*12.70*	Book Value per sh C	*15.00*
91.59	94.81	100.79	108.11	116.04	121.20	132.99	144.10	161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	*252.00*	*254.00*	Common Shs Outst'g D	*260.00*
11.0	12.5	13.5	19.9	13.9	9.6	20.8	--	--	12.4	12.6	22.2	26.8	10.9	13.6	12.5	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*13.0*
.74	.78	.78	1.03	.79	.62	1.07	--	--	.66	.67	1.20	1.42	.66	.91	.80	*estimates*		Relative P/E Ratio	*.85*
3.6%	3.3%	3.2%	2.8%	3.5%	6.0%	5.5%	7.5%	--	--	--	--	1.2%	2.7%	4.0%	4.0%			Avg Ann'l Div'd Yield	*4.9%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $7484.0 mill. Due in 5 Yrs $2745.0 mill.
LT Debt $6361.0 mill. LT Interest $356.0 mill.
Incl. $177.0 mill. capitalized leases.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $29.0 mill.
Pension Assets-12/10 $1.40 bill. Oblig. $1.90 bill.
Pfd Stock $44.0 mill. Pfd Div'd $2.0 mill.
Incl. 441,599 shs. $4.16-$4.50 $100 par, cum., callable at $103.25-$110.
Common Stock 251,800,000 shs.

MARKET CAP: $4.9 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
9597.0	8687.0	5513.0	5472.0	6288.0	6810.0	6519.0	6821.0	6205.0	6432.0	*6600*	*6900*	Revenues ($mill)	*7800*
169.0	d414.0	d40.0	144.0	247.0	158.0	168.0	300.0	231.0	356.0	*380*	*415*	Net Profit ($mill)	*480*
29.8%	--	NMF	18.6%	25.6%	--	37.6%	31.6%	34.6%	38.1%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
22.5%	--	--	--	15.4%	6.3%	3.6%	1.3%	13.0%	2.2%	*8.0%*	*13.0%*	AFUDC % to Net Profit	*12.0%*
80.9%	84.4%	78.2%	75.3%	73.5%	71.7%	70.5%	69.4%	67.9%	70.1%	*69.0%*	*68.5%*	Long-Term Debt Ratio	*64.0%*
18.7%	15.0%	18.3%	21.5%	23.4%	24.9%	25.9%	27.4%	29.0%	29.5%	*30.5%*	*31.0%*	Common Equity Ratio	*35.5%*
10131	7532.0	8652.0	9640.0	9913.0	8961.0	8212.0	8993.0	8977.0	9473.0	*9925*	*10325*	Total Capital ($mill)	*11000*
8362.0	5234.0	6944.0	8636.0	7845.0	7976.0	8728.0	9190.0	9682.0	10069	*10600*	*11325*	Net Plant ($mill)	*13500*
5.0%	NMF	2.7%	4.4%	5.0%	4.5%	4.5%	5.4%	4.7%	5.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
8.7%	NMF	NMF	6.1%	9.4%	6.2%	6.9%	10.9%	8.0%	12.5%	*12.5%*	*12.5%*	Return on Shr. Equity	*12.5%*
8.8%	NMF	NMF	6.2%	9.9%	6.4%	7.2%	11.7%	8.5%	12.5%	*12.5%*	*12.5%*	Return on Com Equity E	*12.5%*
NMF	NMF	NMF	6.2%	9.9%	6.4%	5.1%	8.4%	4.1%	6.9%	*5.5%*	*5.5%*	Retained to Com Eq	*5.0%*
113%	NMF	NMF	11%	6%	10%	35%	31%	54%	46%	*56%*	*57%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-3.5	-4.6	+5.4
Avg. Indust. Use (MWH)	1234	1076	1027
Avg. Indust. Revs. per KWH (¢)	7.67	7.29	8.27
Capacity at Peak (Mw)	9586	8954	9246
Peak Load, Summer (Mw)	7488	7421	8190
Annual Load Factor (%)	59.2	55.9	55.3
% Change Customers (yr-end)	+.4	-.9	+.2

Fixed Charge Cov. (%)	190	159	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-7.0%	-1.5%	1.5%
"Cash Flow"	-6.5%	5.0%	3.5%
Earnings	-7.5%	17.5%	7.0%
Dividends	-9.5%	--	14.0%
Book Value	-6.0%	1.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	2184	1365	1428	1844	6821.0
2009	2104	1225	1263	1613	6205.0
2010	1967	1340	1443	1682	6432.0
2011	2055	1364	*1431*	*1745*	*6600*
2012	*2175*	*1450*	*1500*	*1775*	*6900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.44	.20	.33	.27	1.23
2009	.31	.28	.29	.05	.93
2010	.35	.26	.53	.21	1.33
2011	.51	.26	*.41*	*.27*	*1.45*
2012	*.50*	*.32*	*.43*	*.30*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.05	.05	.05	.05	.20
2008	.09	.09	.09	.09	.36
2009	.125	.125	.125	.125	.50
2010	.15	.15	.15	.21	.66
2011	.21	.21	.21		

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.7 million gas customers. Has 1,166 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 42%; commercial, 31%; industrial, 20%; other, 7%. Generating sources: coal, 48%; gas, 3%; hydro, 1%; purchased, 48%. Fuel costs: 55% of revenues. '10 reported deprec. rates: 3.0% electric, 2.9% gas, 7.4% other. Has 7,800 employees. Chairman: David W. Joos. President & CEO: John G. Russell. Incorporated: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary has electric and gas rate cases pending. Consumers Energy has filed for an electric rate hike of $195 million (5.4%), based on a 10.7% return on a 42.07% common-equity ratio. Under Michigan regulatory law, the utility will self-implement an increase in December. A rate order is due the following June. Consumers is seeking a gas tariff increase of $49 million, based on a 10.7% return on a 41.55% common-equity ratio. The utility will self-implement an increase in March. The rate order is due in September.

The unusually hot weather that the service area experienced this summer will have just a small effect on the company's profits. That's because the utility operates under a mechanism that decouples electric revenues and electric volume. Weather can still affect the bottom line, however. Greater-than-usual storm activity hurt profits by $0.07 a share in the first half of 2011, and Consumers still has sensitivity to weather in the gas side of its business.

We are sticking with our earnings estimates for 2011 and 2012. Our profit estimate of $1.45 a share for this year excludes a $0.12 noncash state income tax benefit that CMS booked in the second quarter. We are treating this gain as a nonrecurring item. (The company's earnings target for 2011 is $1.44 a share.) Our 2012 forecast of $1.55 a share assumes reasonable regulatory treatment. The company has set a target for average annual earnings growth of 5%-7%.

Consumers is building its first wind project. This will provide 100 megawatts of capacity. The $232 million project is expected to be on line by the end of 2012. It will help the utility meet the state's renewable energy requirement.

Financing needs are small. CMS expects to benefit from tax-loss carryforwards in the next few years. No large equity offerings are planned, but the company intends to raise $25 million-$30 million of common equity annually through various stock plans.

This stock's dividend yield and 3- to 5-year total return potential are roughly equivalent to the norms for the electric utility industry.

Paul E. Debbas, CFA *September 23, 2011*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢). '08 EPS don't add due to rounding, '10 due to change in shs. Next egs. report due early Nov. (B) Div'ds historically paid late Feb., May, Aug. & Nov. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '10: $8.39/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '10: 10.7% elec.; in '10: 10.55% gas; earn. on avg. com. eq., '10: 12.6%. Regul. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	35

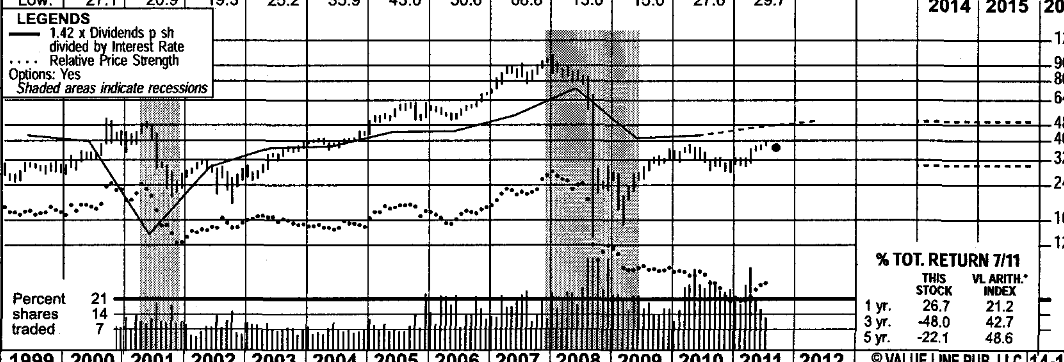
CONSTELLATION EGY. NYSE-CEG

RECENT PRICE	37.08	P/E RATIO	13.7 (Trailing: 32.2 / Median: 16.0)	RELATIVE P/E RATIO	1.01	DIV'D YLD	2.6%	VALUE LINE

TIMELINESS – Suspended 5/6/11
SAFETY 3 New 12/26/08
TECHNICAL – Suspended 5/6/11
BETA .80 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	52.1	50.1	32.4	39.6	44.9	62.6	70.2	104.3	108.0	36.6	38.7	40.2	
Low:	27.1	20.9	19.3	25.2	35.9	43.0	50.6	68.8	13.0	15.0	27.6	29.7	

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+35%)	10%
Low	30	(-20%)	-2%

Insider Decisions

	S	O	N	D	J	F	M	A	M
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	0	0	0	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	158	146	134
to Sell	176	180	178
Hld's(000)	140662	139145	142927

% TOT. RETURN 7/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.7	21.2
3 yr.	-48.0	42.7
5 yr.	-22.1	48.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
19.89	21.35	22.40	22.50	25.32	25.77	24.00	28.53	57.82	71.17	96.08	106.83	118.77	99.53	77.61	71.78	*72.50*	*69.30*	Revenues per sh	*78.00*
4.59	4.45	4.66	4.93	5.57	5.78	5.02	5.50	6.31	6.89	6.78	6.81	7.52	3.36	5.29	4.37	*5.20*	*5.30*	"Cash Flow" per sh	*7.00*
2.02	1.85	1.97	2.06	2.18	2.30	2.20	2.29	2.76	3.19	3.38	3.76	4.29	.48	1.79	1.61	*2.30*	*2.30*	Earnings per sh A	*3.50*
1.55	1.59	1.63	1.67	1.68	1.68	.48	.96	1.04	1.14	1.34	1.51	1.74	1.91	.96	.96	*.96*	*.96*	Div'd Decl'd per sh B ■	*1.00*
2.48	2.44	2.53	2.27	2.92	7.17	8.05	5.05	3.92	3.99	4.26	5.33	7.26	9.71	7.61	4.98	*4.20*	*5.00*	Cap'l Spending per sh	*6.75*
19.07	19.35	19.44	19.98	20.01	20.95	23.48	23.43	24.67	26.81	27.57	25.53	29.93	15.98	43.27	39.19	*40.40*	*41.65*	Book Value per sh C	*48.00*
147.53	147.67	147.67	149.25	149.56	150.53	163.71	164.84	167.82	176.33	178.30	180.52	178.44	199.13	200.99	199.79	*201.00*	*202.00*	Common Shs Outst'g D	*205.00*
12.4	14.7	14.0	15.3	13.2	15.8	16.4	12.1	11.8	12.5	16.0	15.6	20.5	NMF	15.5	20.5	*Bold figures are*		Avg Ann'l P/E Ratio	*11.5*
.83	.92	.81	.80	.75	1.03	.84	.66	.67	.66	.85	.84	1.09	NMF	1.03	1.31	*Value Line*		Relative P/E Ratio	*.75*
6.2%	5.9%	5.9%	5.3%	5.8%	4.6%	1.3%	3.5%	3.2%	2.9%	2.5%	2.6%	2.0%	2.9%	3.5%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*2.5%*
						3928.3	4703.0	9703.0	12550	17132	19285	21193	19818	15599	14340	*14500*	*14000*	Revenues ($mill)	*16000*
						366.3	372.1	472.2	567.8	619.9	696.8	796.4	99.2	372.4	336.3	*480*	*480*	Net Profit ($mill)	*760*
						34.6%	40.3%	35.6%	27.1%	24.8%	31.0%	33.7%	65.4%	17.6%	35.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						15.7%	11.8%	2.9%	1.9%	1.6%	2.0%	2.4%	50.4%	23.4%	9.8%	*2.0%*	*3.0%*	AFUDC % to Net Profit	*4.0%*
						40.2%	53.2%	53.8%	49.5%	46.1%	46.8%	45.7%	60.2%	35.1%	35.7%	*30.5%*	*32.5%*	Long-Term Debt Ratio	*31.5%*
						57.0%	44.6%	44.2%	48.6%	51.9%	51.1%	52.4%	37.6%	63.5%	62.8%	*68.0%*	*66.0%*	Common Equity Ratio	*67.0%*
						6746.1	8666.2	9369.7	9730.1	9474.8	9021.6	10191	8470.1	13701	12468	*11925*	*12750*	Total Capital ($mill)	*14700*
						7700.4	7957.1	9601.5	10087	10067	9222.1	9767.1	10717	8453.8	9278.8	*9550*	*9950*	Net Plant ($mill)	*11900*
						6.5%	5.9%	6.7%	7.4%	8.0%	9.3%	9.1%	3.2%	4.0%	3.6%	*5.0%*	*4.5%*	Return on Total Cap'l	*6.0%*
						9.1%	9.2%	10.9%	11.5%	12.1%	14.5%	14.4%	2.9%	4.2%	4.2%	*6.0%*	*5.5%*	Return on Shr. Equity	*7.5%*
						9.2%	9.3%	11.1%	11.7%	12.3%	14.8%	14.7%	2.7%	4.1%	4.1%	*6.0%*	*5.5%*	Return on Com Equity E	*7.5%*
						6.0%	5.7%	7.0%	7.7%	7.7%	9.1%	8.9%	NMF	1.5%	1.8%	*3.5%*	*3.5%*	Retained to Com Eq	*5.5%*
						37%	41%	39%	36%	39%	40%	40%	NMF	65%	58%	*43%*	*43%*	All Div'ds to Net Prof	*29%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $4557.9 mill. **Due in 5 Yrs** $1515.7 mill.
LT Debt $4442.1 mill. **LT Interest** $266.5 mill.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $202.1 mill.
Pension Assets-12/10 $1.41 bill. Oblig. $1.63 bill.
Pfd Stock $190.0 mill. **Pfd Div'd** $13.2 mill.
Incl. 1,900,000 shs. 6.70%-7.125% preference, callable at $102.68-$103.50, all $100 par, not subject to mandatory redemption.
Common Stock 200,702,529 shs. as of 4/29/11
MARKET CAP: $7.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-3.5	-1.2	+4.1
Avg. Indust. Use (MWH)	601	571	516
Avg. Indust. Revs. per KWH (¢)	12.93	11.26	10.75
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Nuclear Capacity Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.3	+.3
Fixed Charge Cov. (%)	156	218	286

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	13.0%	2.0%	*-1.0%*
"Cash Flow"	-2.0%	-8.0%	*8.5%*
Earnings	-5.0%	-16.0%	*18.0%*
Dividends	-2.5%	1.5%	*-4.0%*
Book Value	5.0%	4.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	4812	4756	5323	4926	19818
2009	4303	3864	4027	3403	15598
2010	3586	3309	3968	3474	14340
2011	3570	3360	*4070*	*3500*	*14500*
2012	*3500*	*3300*	*3800*	*3400*	*14000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.81	.95	.35	d1.63	.48
2009	.30	.66	1.00	d.17	1.79
2010	.95	.36	.18	.13	1.61
2011	.35	.49	*.81*	*.65*	*2.30*
2012	*.75*	*.45*	*.60*	*.50*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.3775	.435	.435	.435	1.68
2008	.435	.4775	.4775	.4775	1.87
2009	.4775	.24	.24	.24	1.20
2010	.24	.24	.24	.24	.96
2011	.24	.24	.24		

BUSINESS: Constellation Energy Group, Inc. is a holding company for Baltimore Gas and Electric Company, which distributes electricity and gas in Baltimore and parts of central Maryland. Has 1.2 million electric, 653,000 gas customers. Has nonregulated businesses: *Constellation Energy Commodities* Group and Constellation NewEnergy. Electric revenue breakdown: residential, 67%; commercial, 26%; industrial, 2%; other, 5%. Generating sources: nuclear, 45%; coal, 37%; gas, 13%; other, 5%. Fuel costs: 76% of revenues. '10 reported depr. rates: generating assets, 2.9%; utility, 3.2%. Has 7,600 employees. Chairman, President & CEO: Mayo A. Shattuck III. Inc.: MD. Address: 100 Constellation Way, Baltimore, MD 21202. Tel.: 410-470-2800. Internet: www.constellation.com.

The proposed acquisition of Constellation Energy by Exelon has received some criticism in Maryland. The deal calls for Constellation stockholders to get 0.93 of a share of Exelon (valued at $39.22) for each of their shares. Each company's shareholders, the regulatory commissions in Maryland and New York, and the Federal Energy Regulatory Commission and other federal agencies must approve the combination. The companies are targeting early 2012 for completion. However, even though Exelon has offered $250 million in merger-related benefits to Maryland ratepayers (including a $100 credit for each residential customer), some intervenor groups believe that this isn't enough and are asking for more.

We now advise Constellation stockholders to sell their shares on the open market. Exelon's offer is reasonable, and Constellation stockholders stand to benefit from a doubling of their dividends if the deal goes through. However, investors should remember that Exelon terminated its agreement to buy Public Service Enterprise Group when the concessions sought by intervenors in New Jersey became more than Exelon was willing to provide. The stock is still trading at a discount of only about 5% to the value of Exelon's offer, which is too low in view of the uncertainty surrounding the regulatory process in Maryland. The Timeliness rank of Constellation stock remains suspended due to the takeover agreement.

Constellation's nonregulated businesses have differing prospects. Low power prices are squeezing margins from the output of the company's generating assets. On the other hand, the retail energy-supply business is benefiting from low prices, which are stimulating customer demand. Constellation has made two acquisitions that expanded its presence in this business materially, from fewer than 300,000 customers to almost a million.

We have cut our 2011 share-net estimate by $0.15, to $2.30, because June-quarter results fell short of our forecast. Our 2012 estimate remains at $2.30. This company's earnings are hard to predict because each quarter's tally contains the effects of unusual items, such as mark-to-market accounting gains or losses.

Paul E. Debbas, CFA *August 26, 2011*

(A) *Diluted* EPS. Excl. nonrec. gains (losses): '02, 91¢; '03, ($1.09); '04, (8¢); '05, (4¢); '06, 36¢; '07, 22¢; '08, ($7.81); '09, $20.40; '10, ($6.51); gains (loss) from disc. ops.: '05, 13¢; '06, $1.04; '07, (1¢). '10 EPS don't add due to rounding. Next egs. report due early Nov. (B) Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '10: $2.26/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '10: 9.86% elec., 9.56% gas; earned on avg. com. eq., '10: 3.6%. Reg. Climate: Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	50
Price Growth Persistence	35
Earnings Predictability	20

DTE ENERGY CO. NYSE-DTE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
49.54	13.4	(Trailing: 13.9 Median: 15.0)	1.00	4.8%

VALUE LINE

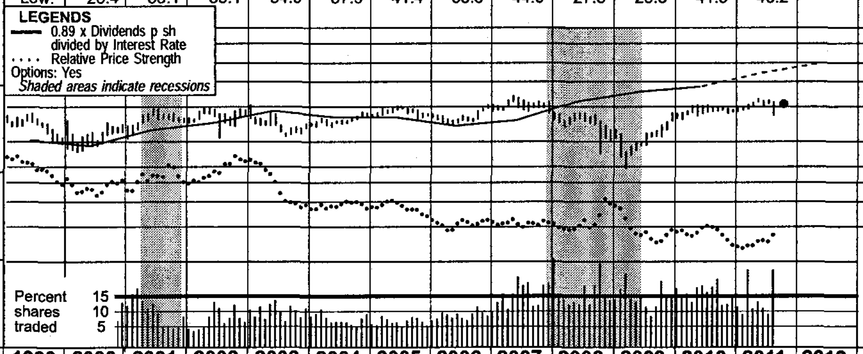
TIMELINESS 2 Raised 8/12/11

SAFETY 3 Lowered 10/5/01

TECHNICAL 3 Lowered 9/16/11

BETA .75 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	41.3	47.1	47.7	49.5	45.5	48.3	49.2	54.7	45.3	45.0	49.1	52.8
Low:	28.4	33.1	33.1	34.0	37.9	41.4	38.8	44.0	27.8	23.3	41.3	43.2



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+40%)	13%
Low	45	(-10%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	3	6	0	12	1
to Sell	0	2	0	0	3	6	0	11	1

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	145	142	162
to Sell	198	178	154
Hld's(000)	94168	97304	96500

Target Price Range

2014 | 2015 | 2016

120, 100, 80, 64, 48, 32, 24, 20, 16, 12, 8

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.2	19.4
3 yr.	41.1	26.8
5 yr.	56.3	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
25.05	25.12	25.94	29.10	32.60	39.24	48.71	40.30	41.76	40.84	50.74	50.93	54.28	57.23	48.45	50.51	**51.90**	**54.40**	Revenues per sh	**61.75**
7.07	7.10	7.42	7.61	8.40	8.59	6.98	8.31	6.95	6.81	8.14	8.19	8.48	8.26	9.38	9.78	**9.50**	**9.95**	"Cash Flow" per sh	**11.25**
3.02	2.80	2.88	3.05	3.33	3.27	2.15	3.83	2.85	2.55	3.27	2.45	2.66	2.73	3.24	3.74	**3.60**	**3.75**	Earnings per sh A	**4.25**
2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.08	2.12	2.12	2.12	2.18	**2.32**	**2.42**	Div'd Decl'd per sh B ■	**2.70**
3.13	3.66	3.14	3.83	5.10	5.25	6.80	5.88	4.45	5.19	5.99	7.92	7.96	8.42	6.26	6.49	**10.20**	**8.80**	Cap'l Spending per sh	**10.25**
23.68	23.73	24.55	25.49	26.95	28.15	28.48	27.26	31.36	31.85	32.44	33.02	35.86	36.77	37.96	39.67	**41.00**	**42.30**	Book Value per sh C	**46.50**
145.12	145.12	145.10	145.07	145.04	142.65	161.13	167.46	168.61	174.21	177.81	177.14	163.23	163.02	165.40	169.43	**169.50**	**170.00**	Common Shs Outst'g D	**174.00**
10.0	11.2	10.3	13.3	11.6	10.3	19.3	11.3	13.7	16.0	13.8	17.4	18.3	14.8	10.4	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	**13.5**
.67	.70	.59	.69	.66	.67	.99	.62	.78	.85	.73	.94	.97	.89	.69	.79	*Value Line*		Relative P/E Ratio	**.90**
6.9%	6.6%	6.9%	5.1%	5.3%	6.1%	5.0%	4.8%	5.3%	5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	*estimates*		Avg Ann'l Div'd Yield	**4.7%**

CAPITAL STRUCTURE as of 6/30/11
Total Debt $7984.0 mill. **Due in 5 Yrs** $3176.0 mill.
LT Debt $7507.0 mill. **LT Interest** $428.0 mill.
Incl. $37.0 mill. capitalized leases, $289.0 mill. *Trust Preferred Securities, and $559.0 mill.* securitized bonds.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $39.0 mill.
Pension Assets-12/10 $2.91 bill. **Oblig.** $3.79 bill.

Pfd Stock None

Common Stock 169,328,889 shs.

MARKET CAP: $8.4 billion (Large Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
7849.0	6749.0	7041.0	7114.0	9022.0	9022.0	8861.0	9329.0	8014.0	8557.0	**8800**	**9250**	Revenues ($mill)	**10750**
329.0	632.0	480.0	443.0	576.0	437.0	453.0	445.0	532.0	630.0	**620**	**650**	Net Profit ($mill)	**745**
--	--	--	27.1%	26.0%	23.9%	25.1%	34.9%	31.6%	32.7%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
.9%	4.9%	1.3%	.7%	1.0%	5.0%	7.1%	11.2%	2.6%	1.6%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
63.3%	63.0%	59.2%	57.8%	55.1%	56.1%	54.4%	56.4%	54.0%	51.3%	**52.5%**	**51.5%**	Long-Term Debt Ratio	**52.0%**
36.7%	37.0%	40.8%	42.2%	44.9%	43.9%	45.6%	43.6%	46.0%	48.7%	**47.5%**	**48.5%**	Common Equity Ratio	**48.0%**
12517	12350	12956	13154	12849	13323	12824	13736	13648	13811	**14575**	**14825**	Total Capital ($mill)	**16900**
9543.0	9813.0	10324	10491	10830	11451	11408	12231	12431	12992	**13725**	**14175**	Net Plant ($mill)	**15800**
4.4%	7.3%	5.6%	5.2%	6.3%	5.1%	5.3%	5.0%	5.7%	6.3%	**5.5%**	**6.0%**	Return on Total Cap'l	**6.0%**
7.2%	13.8%	9.1%	8.0%	10.0%	7.5%	7.7%	7.4%	8.5%	9.4%	**9.0%**	**9.0%**	Return on Shr. Equity	**9.0%**
7.2%	13.8%	9.1%	8.0%	10.0%	7.5%	7.7%	7.4%	8.5%	9.4%	**9.0%**	**9.0%**	Return on Com Equity E	**9.0%**
.1%	6.4%	2.5%	1.6%	3.7%	1.2%	1.5%	1.7%	2.9%	4.0%	**3.0%**	**3.0%**	Retained to Com Eq	**3.5%**
99%	53%	72%	80%	63%	84%	80%	77%	65%	57%	**63%**	**63%**	All Div'ds to Net Prof	**63%**

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.7	-5.6	-.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	11011	10627	11365
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.6	-.8	-.4
Fixed Charge Cov. (%)	205	223	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	4.5%	3.0%	*3.0%*
"Cash Flow"	1.0%	4.5%	*3.5%*
Earnings	--	2.5%	*4.5%*
Dividends	.5%	1.0%	*4.0%*
Book Value	3.5%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	2570	2251	2338	2170	9329.0
2009	2255	1688	1950	2121	8014.0
2010	2453	1792	2139	2173	8557.0
2011	2431	2028	**2150**	**2191**	**8800**
2012	**2600**	**2050**	**2250**	**2350**	**9250**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.73	.17	1.03	.80	2.73
2009	1.09	.51	.92	.72	3.24
2010	1.38	.51	.96	.90	3.74
2011	1.04	.67	**.99**	**.90**	**3.60**
2012	**1.15**	**.70**	**1.00**	**.90**	**3.75**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.53	.53	.53	.53	2.12
2008	.53	.53	.53	.53	2.12
2009	.53	.53	.53	.53	2.12
2010	.53	.53	.53	.56	2.15
2011	.56	.56	.5875		

BUSINESS: DTE Energy Company is a holding company for The Detroit Edison Company, which supplies electricity in Detroit and a *7,600-square-mile area* in southeastern Michigan, and Michigan Consolidated Gas (MichCon). Customers: 2.1 mill. electric, 1.3 mill. gas. Acquired MCN Energy 6/01. Has various nonutility operations. Electric revenue breakdown: residential, 41%; commercial, 33%; industrial, 14%; other, 12%. Generating sources: coal, 72%; nuclear, 14%; gas, 1%; purchased, 13%. Fuel costs: 37% of revenues. '10 reported deprec. rates: 3.3% electric, 2.5% gas. Has 9,800 employees. Chairman, President & CEO: Gerard M. Anderson. Inc.: Michigan. Address: One Energy Plaza, Detroit, Michigan 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary is awaiting a decision on its rate case. Detroit Edison is seeking a rate hike of $361 million, based on a return of 11.125% on a common-equity ratio of 49%. The utility is also asking for a change in its revenue decoupling mechanism so that only the lost volume stemming from energy efficiency measures is considered. Thus, Detroit Edison would benefit from a rebound in kilowatt-hour sales once the service area's economy starts to recover. The staff of the Michigan Public Service Commission (MPSC) is recommending a $162 million rate boost, and an administrative law judge is proposing a raise of $156 million. The staff and ALJ are recommending a 10.15% return on a common-equity ratio of 49%. In April, the utility self-implemented an increase of $107 million, under *a regulatory mechanism* that is unique to Michigan. The MPSC's order is due in October.

We have raised our 2011 earnings estimate by $0.15 a share, to $3.60. June-quarter profits were better than we expected. Our estimate remains within management's targeted range of $3.40-$3.70 a share. Even so, profits are likely to decline for the year because, in 2010, DTE's nonutility investments benefited from high coke prices and a federal tax credit that wasn't renewed. We look for earnings growth of 4% next year, based on improvement at both the utility and nonutility sides of DTE's operations.

A couple of projects are under development. Detroit Edison is building a 102-megawatt wind project at an expected cost of $250 million. It should be in service in late 2011 or early 2012. DTE has also signed an agreement to build a pipeline and gathering project to serve a gas producer. This investment, which will amount to about $280 million, should begin service in mid-2002.

By utility standards, this timely stock has a yield and 3- to 5-year total return potential that are somewhat above the industry averages. Our long-term projections could prove conservative depending upon the success of DTE's planned monetization of its acreage in the Barnett Shale region of Texas. The company intends to do this in 2012 or early 2013.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '03, (16¢); '05, (2¢); '06, 1¢; '07, $1.96; '08, 50¢; '11, 52¢; gains (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢. '10 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '10: $40.57/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '10 (electric and gas): 11%; earned on avg. com. eq., '10: 9.0%. Regulatory Climate: Avg.

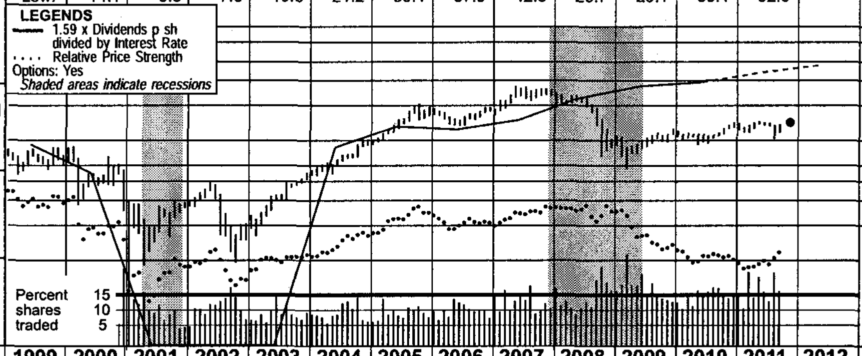
Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	70

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE **39.53** | P/E RATIO **14.2** (Trailing: 12.4; Median: 11.0) | RELATIVE P/E RATIO **1.01** | DIV'D YLD **3.3%** | VALUE LINE

TIMELINESS **3** Lowered 3/11/11
SAFETY **3** Raised 11/11/05
TECHNICAL **3** Lowered 9/2/11
BETA .80 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	30.0	16.1	19.6	22.1	32.5	49.2	47.2	60.3	55.7	36.7	39.4	40.2
Low:	14.1	6.3	7.8	10.6	21.2	30.4	37.9	42.8	26.7	23.1	30.4	32.6



Target Price Range 2014 | 2015 | 2016

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	30	(-25%)	-3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	0	1	0	1	0	0	0
to Sell	0	0	0	1	0	1	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	184	167	155
to Sell	197	194	210
Hld's(000)	251635	248100	248068

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.0	-4.8
3 yr.	7.0	25.0
5 yr.	7.6	16.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
18.95	20.13	24.58	29.12	27.85	35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	*37.45*	*38.65*	Revenues per sh	*44.50*
3.95	4.45	5.49	6.65	7.20	d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	*7.85*	*8.10*	"Cash Flow" per sh	*9.00*
1.66	1.64	1.75	1.86	2.03	d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	*2.75*	*2.80*	Earnings per sh A	*3.25*
1.00	1.00	1.00	1.04	1.08	.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	*1.29*	*1.31*	Div'd Decl'd per sh B ■	*1.40*
2.18	1.75	2.08	2.75	3.55	4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	*15.65*	*16.25*	Cap'l Spending per sh	*13.25*
14.34	15.07	14.71	14.55	15.01	7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	*33.85*	*35.30*	Book Value per sh C	*40.25*
443.61	424.52	375.76	350.55	347.21	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g D	*325.81*
10.0	10.8	13.7	15.1	12.9	--	10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	9.7	10.3	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.67	.68	.79	.79	.74	--	.51	.43	.40	NMF	.62	.70	.85	.75	.65	.66	*Value Line*		Relative P/E Ratio	*.85*
6.0%	5.7%	4.2%	3.7%	4.1%	3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
11436	11488	12135	10199	11852	12622	13113	14112	12374	12409	*12200*	*12600*	Revenues ($mill)	*14500*
536.1	644.0	738.0	220.0	1132.0	1134.0	1151.0	1266.0	1115.0	1153.0	*960*	*985*	Net Profit ($mill)	*1120*
NMF	37.8%	22.4%	--	26.0%	31.4%	27.3%	30.7%	33.0%	32.1%	*32.5%*	*32.0%*	Income Tax Rate	*32.0%*
--	3.3%	3.7%	11.4%	4.9%	5.1%	8.2%	8.9%	10.5%	16.9%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*9.0%*
73.3%	66.6%	68.1%	60.5%	54.6%	51.3%	49.1%	51.2%	49.3%	51.8%	*51.5%*	*51.5%*	Long-Term Debt Ratio	*53.5%*
18.9%	25.6%	31.1%	37.8%	40.9%	43.5%	46.0%	44.5%	46.5%	44.3%	*44.5%*	*44.5%*	Common Equity Ratio	*43.0%*
17279	17352	17299	15995	16167	17725	18375	21374	21185	23861	*24875*	*25800*	Total Capital ($mill)	*30400*
8013.0	8247.0	12587	13475	14469	15913	17403	18969	21966	24778	*28225*	*31825*	Net Plant ($mill)	*39500*
6.6%	6.7%	7.2%	4.2%	9.4%	8.6%	8.3%	7.4%	6.9%	6.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
11.6%	11.1%	13.4%	3.5%	15.4%	13.1%	12.3%	12.1%	10.4%	10.0%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.0%*
13.6%	11.9%	13.6%	3.5%	16.7%	14.0%	13.0%	12.8%	10.8%	10.4%	*8.0%*	*8.5%*	Return on Com Equity E	*8.0%*
13.6%	11.9%	13.6%	NMF	12.2%	10.1%	9.2%	8.6%	6.7%	6.5%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
17%	18%	1%	NMF	29%	31%	33%	35%	41%	40%	*50%*	*49%*	All Div'ds to Net Prof	*46%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $13397 mill. **Due in 5 Yrs** $2838.0 mill.
LT Debt $12956 mill. **LT Interest** $773.0 mill.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $1.14 bill.
Pension Assets-12/10 $3.24 bill. **Oblig.** $4.08 bill.
Pfd Stock $1029 mill. **Pfd Div'd** $59.0 mill.
4,800,198 shs. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh. 8,000,000 shs. 5.349%-6.125%, $100 par; 1,250,000 shs. 6.5%, $100 liquidation value.
Common Stock 325,811,206 shs.
as of 8/1/11
MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+1.1	-4.4	-2.7
Avg. Indust. Use (MWH)	711	669	710
Avg. Indust. Revs. per KWH (¢)	6.88	6.95	7.38
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22020	22112	22771
Annual Load Factor (%)	55.6	53.4	50.7
% Change Customers (yr-end)	+.3	+.4	+.5
Fixed Charge Cov. (%)	298	268	240

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	2.5%	2.5%	2.0%
"Cash Flow"	6.5%	8.0%	1.5%
Earnings	--	10.0%	-1.0%
Dividends	2.5%	15.5%	2.0%
Book Value	9.5%	10.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	3113	3477	4295	3227	14112
2009	2812	2834	3678	3050	12374
2010	2810	2742	3788	3069	12409
2011	2782	2983	*3535*	*2900*	*12200*
2012	*2900*	*3000*	*3700*	*3000*	*12600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.92	.79	1.31	.66	3.68
2009	.78	.78	1.08	.59	3.24
2010	.70	.62	1.46	.58	3.35
2011	.62	.54	*1.05*	*.54*	*2.75*
2012	*.65*	*.55*	*1.05*	*.55*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.29	.29	.29	.29	1.16
2008	.305	.305	.305	.305	1.22
2009	.31	.31	.31	.31	1.24
2010	.315	.315	.315	.315	1.26
2011	.32	.32	.32	.32	

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison (SCE), which supplies electricity to 4.9 million customers in a 50,000 sq. mi. area in central, coastal, and southern California (excl. Los Angeles and San Diego). Edison Mission Group (EMG) is an independent power producer. Electric revenue breakdown: residential, 40%; commercial, 45%; industrial, 6%; other, 9%. Generating sources: nuclear, 20%; gas, 8%; coal, 6%; hydro, 5%; purchased, 61%. Fuel costs: 33% of revs. '10 reported deprec. rate (utility): 4.1%. Has 20,100 employees. Chairman, President & CEO: Theodore F. Craver, Jr. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

Edison International's utility subsidiary has a rate case pending. Southern California Edison is seeking increases of $824 million next year, $136 million in 2013, and $532 million in 2014. New tariffs will take effect at the start of 2012. The current filing does not deal with the cost of capital. In April of 2012, SCE will put forth a cost-of-capital application.

The utility's prospects are good. SCE is performing well, and its earning power rises as its rate base increases. In fact, the utility forecasts that its rate base will rise at a compounded annual growth rate of 8%-11% through 2014. Despite the positive trends at SCE . . .

Earnings are headed down in 2011. The rise in income we expect from the utility will be outweighed by a significant bottom-line decline at Edison Mission Group (EMG), the nonregulated side of Edison International's business. Low power prices are the problem. In fact, the nonregulated operations are likely to fall into the red this year. Management's earnings guidance of $2.60-$2.90 reflects a $0.19-a-share deficit at EMG, compared with a profit of $0.59 a share in 2010. We expect just a slight earnings recovery for the company as a whole in 2012.

Stricter environmental regulations are a concern for Edison International's nonregulated coal-fired assets. In the current environment of low power prices, the company must decide whether market conditions justify the capital spending needed to keep the plants operating in the long run. Although forward prices for power to be sold in mid-decade suggest that higher environmental costs will eventually be reflected in market prices, this doesn't necessarily mean that Edison will make the upgrades.

We expect a dividend hike at the board meeting in December. This has been the pattern in recent years. We estimate the same $0.02-a-share boost in the yearly disbursement as in the past three years. Edison wants to pay out 45%-55% of *SCE's* (not the company's) earnings, so as long as the utility's income is rising, dividend increases are probable.

This stock's yield is low, by utility standards. Total return potential to 2014-2016 is unexciting, too.

Paul E. Debbas, CFA *November 4, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '01, $1.88; '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; gain (losses) from disc. ops.: '07, (1¢); '09, (2¢); '10, 1¢; '11, (1¢). Incl. nonrec. losses: '00, $7.58; '01, $1.88. '09 & '10 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid late Jan., Apr., July & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd charges. In '10: $13.34/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '08: 11.5%; earned on avg. com. eq., '10: 10.8%. Reg. Clim.: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	55

GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE	19.19	P/E RATIO	14.3 (Trailing: 15.5 / Median: 15.0)	RELATIVE P/E RATIO	1.07	DIV'D YLD	4.3%	VALUE LINE

TIMELINESS 3 Lowered 12/17/10

SAFETY 3 Lowered 12/26/08

TECHNICAL 3 Lowered 9/16/11

BETA .75 (1.00 = Market)

2014-16 PROJECTIONS

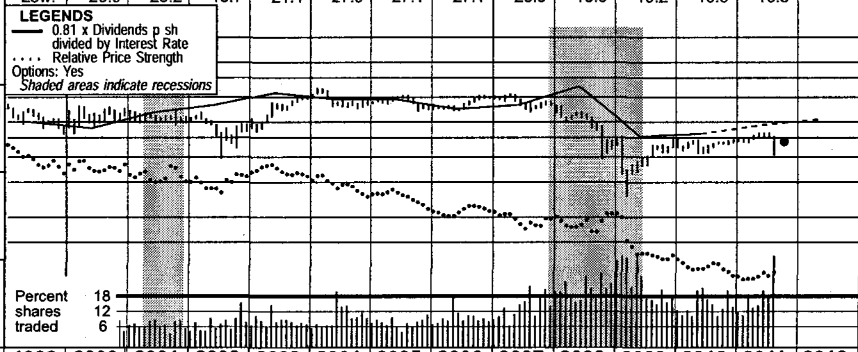
	Price	Gain	Ann'l Total Return
High	25	(+30%)	11%
Low	16	(-15%)	1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	98	103	107
to Sell	106	96	110
Hld's(000)	90060	94368	94349



Target Price Range 2014 | 2015 | 2016

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.3	19.4
3 yr.	-3.0	26.8
5 yr.	-16.2	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
					29.0	27.6	27.0	32.8	35.7	32.8	32.8	33.4	29.3	20.5	19.9	21.3		High:	
					20.9	23.2	15.7	21.4	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3		Low:	
14.31	14.60	14.47	15.17	14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	*16.90*	*16.15*	Revenues per sh	*19.25*
4.06	3.90	3.91	4.21	3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	*3.55*	*3.65*	"Cash Flow" per sh	*4.75*
1.92	1.69	1.69	1.89	1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	*1.20*	*1.45*	Earnings per sh A	*1.75*
1.54	1.59	1.62	1.64	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	*.83*	*.83*	Div'd Decl'd per sh B ■	*1.10*
2.20	1.66	2.05	1.97	2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	*3.75*	*4.05*	Cap'l Spending per sh	*3.50*
14.50	14.71	14.19	14.41	13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	*21.65*	*21.50*	Book Value per sh C	*23.50*
61.91	61.91	61.91	61.91	61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	*136.00*	*155.00*	Common Shs Outst'g D	*155.00*
12.2	15.9	17.0	15.7	20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	*Bold figures are*		Avg Ann'l P/E Ratio	*11.5*
.82	1.00	.98	.82	1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.78	*Value Line*		Relative P/E Ratio	*.75*
6.5%	5.9%	5.6%	5.5%	6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*
						1461.9	1861.9	2149.5	2464.0	2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	*2300*	*2500*	Revenues ($mill)	*3000*
						100.0	129.2	159.0	178.8	164.2	127.6	159.2	119.5	135.6	211.7	*165*	*215*	Net Profit ($mill)	*280*
						16.6%	27.2%	34.2%	24.1%	18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	*34.0%*	*34.0%*	Income Tax Rate	*34.0%*
						12.8%	1.0%	1.8%	2.0%	2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	*6.0%*	*7.0%*	AFUDC % to Net Profit	*4.0%*
						53.1%	53.5%	53.8%	44.8%	47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	*52.0%*	*50.5%*	Long-Term Debt Ratio	*51.0%*
						44.6%	44.7%	44.4%	53.4%	50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	*47.5%*	*49.0%*	Common Equity Ratio	*48.5%*
						1747.4	2102.8	2154.6	2137.1	2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	*6210*	*6840*	Total Capital ($mill)	*7500*
						2623.7	2604.1	2700.9	2734.5	2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	*7085*	*7365*	Net Plant ($mill)	*7925*
						7.5%	7.7%	9.0%	10.1%	8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.5%*
						12.2%	13.2%	16.0%	15.1%	13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	*5.5%*	*6.5%*	Return on Shr. Equity	*7.5%*
						12.6%	13.6%	16.4%	15.5%	13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	*5.5%*	*6.5%*	Return on Com Equity E	*7.5%*
						NMF	2.3%	4.4%	5.1%	3.2%	NMF	.9%	NMF	.9%	3.4%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
						104%	83%	73%	68%	76%	104%	91%	NMF	81%	54%	*68%*	*57%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $3975.8 mill. **Due in 5 Yrs** $1721.1 mill.
LT Debt $2860.8 mill. **LT Interest** $192.5 mill.
Incl. $287.5 mill. 10% equity units subject to mandatory conversion in 2012.
(LT interest earned: 2.0x)
Leases, Uncapitalized Annual rentals $17.9 mill.
Pension Assets-12/10 $353.8 mill.
Oblig. $911.4 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 136,007,431 shs. **as of 7/29/11**
MARKET CAP: $2.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+22.5	+18.1	+5.6
Avg. Indust. Use (MWH)	966	1367	1429
Avg. Indust. Revs. per KWH (¢)	5.23	5.47	5.89
Capacity at Peak (Mw)	4164	6336	6272
Peak Load, Summer (Mw)	3495	5347	5531
Annual Load Factor (%)	52.8	51.3	52.8
% Change Customers (avg.)	+.6	-1.2	+.2
Fixed Charge Cov. (%)	188	144	218

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-.5%	-14.5%	*4.0%*
"Cash Flow"	-1.5%	-5.5%	*5.5%*
Earnings	-3.5%	-11.5%	*6.0%*
Dividends	-4.0%	-8.0%	*Nil*
Book Value	4.0%	7.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	297.6	335.0	593.6	443.9	1670.1
2009	419.2	480.5	587.7	477.6	1965.0
2010	506.9	552.0	728.8	467.8	2255.5
2011	492.9	565.1	*742*	*500*	*2300*
2012	*550*	*600*	*800*	*550*	*2500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	d.07	.15	.92	.06	1.16
2009	.05	.28	.57	.10	1.03
2010	.15	.47	.96	d.04	1.53
2011	.01	.31	*.73*	*.15*	*1.20*
2012	*.15*	*.35*	*.80*	*.15*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.415	.415	.415	.415	1.66
2008	.415	.415	.415	.415	1.66
2009	.2075	.2075	.2075	.2075	.83
2010	.2075	.2075	.2075	.2075	.83
2011	.2075	.2075	.2075		

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 825,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: *residential*, 41%; *commercial*, 38%; *industrial*, 9%; other, 12%. Generating sources: coal, 66%; nuclear, 14%; gas & oil, 2%; wind, 1%; purchased, 17%. Fuel costs: 29% of revs. '10 reported deprec. rate (utility): 3.0%. Has 3,000 employees. Chairman & CEO: Michael J. Chesser. President & COO: Terry Bassham. Inc.: MO. Address: 1200 Main St., Kansas City, MO 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

This has been a difficult year for Great Plains Energy. An extended outage at the Wolf Creek nuclear plant cut share earnings by $0.05 in the June quarter. Flooding in the Midwest has reduced the amount of coal that can be delivered to the company's plants. The reliance on more-costly sources of power is a problem for Kansas City Power & Light, which lacks a fuel adjustment clause in Missouri. This will lower profits by an estimated $0.08-$0.12 a share in the second half of 2011. And, the weak economy is lessening the demand for power. Any volume growth this year is likely to come from the effects of an unusually hot summer. Finally, the service area was hit with severe storms in August. Not all has gone wrong; in June, the utilities received rate hikes in Missouri. All told, Great Plains figures profits will wind up in a range of $1.10-$1.25 a share this year. We have trimmed our estimate by a nickel a share, to $1.20.

Regulatory lag is a problem. The normal delay in recovering costs will hurt share net by an estimated $0.20 this year and $0.22 next year. To combat this problem, the utilities plan to file rate cases in late 2011 or early 2012. They also want the states to institute regulatory mechanisms, such as rate riders and cost trackers, that will enable quicker cost recovery.

We were too optimistic about the company's prospects for 2012. In our June report, we forecasted earnings of $1.60 a share next year, but upon reporting June-quarter results, management issued guidance of $1.35-$1.55 for 2012. So we cut our estimate by $0.15. We now believe a dividend hike won't come until 2013, although we don't rule one out in 2012. Great Plains is targeting a payout ratio of 50%-70%.

The Kansas commission approved a project for environmental retrofits to the LaCygne coal-fired station. The portion of the $615 million project that is allocated to Kansas will be $281 million. The rest of the costs are allocated to Missouri. The utility will have to recover the expenditures through a general rate application in each state.

We believe this stock's yield isn't high enough to compensate investors for the uncertainties that the company is facing.

Paul E. Debbas, CFA *September 23, 2011*

(A) Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on discont. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢; '09, (1¢). '08-'10 EPS don't add due to change in shares or rounding. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '10: $8.05/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in MO in '11: 10%; in KS in '10: 10%; earned on avg. com. eq., '10: 7.3%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	70

HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE **24.96** | P/E RATIO **18.5** (Trailing: 21.0; Median: 19.0) | RELATIVE P/E RATIO **1.31** | DIV'D YLD **5.0%** | **VALUE LINE**

TIMELINESS 3 Lowered 11/19/10
SAFETY 3 Lowered 5/8/09
TECHNICAL 3 Lowered 10/28/11
BETA .70 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	19.0	20.6	24.5	24.0	29.5	29.8	28.9	27.5	29.8	22.7	25.0	26.4
Low:	13.8	16.8	17.3	19.1	23.0	24.6	25.7	20.3	21.0	12.1	18.6	20.6

2014-16 PROJECTIONS

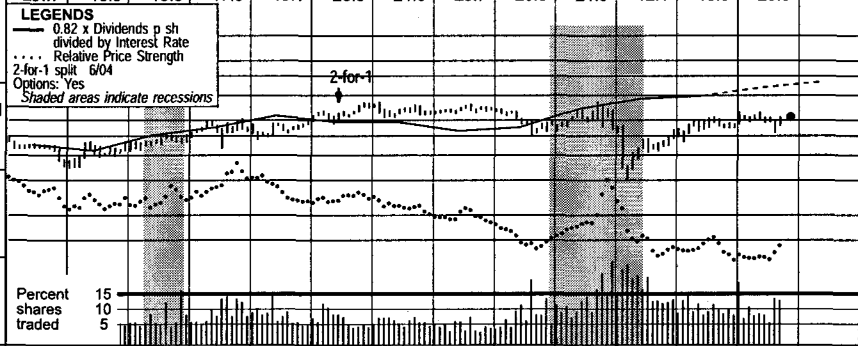
	Price	Gain	Ann'l Total Return
High	30	(+20%)	9%
Low	19	(-25%)	-1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	1	2	0	0	1	0	1
Options	1	0	0	0	0	1	0	0	0
to Sell	1	0	0	2	0	2	1	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	97	91	74
to Sell	81	82	91
Hld's(000)	35955	38026	36557



Target Price Range

2014 | 2015 | 2016

64 48 40 32 24 20 16 12 8 6

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.5	-4.8
3 yr.	-0.3	25.0
5 yr.	18.7	16.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
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	35.56	24.96	28.14	*32.30*	*35.95*	Revenues per sh	*40.25*
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	2.72	2.59	2.88	*3.05*	*3.30*	"Cash Flow" per sh	*3.75*
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	1.07	.91	1.21	*1.30*	*1.45*	Earnings per sh A	*2.00*
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	1.24	*1.24*	*1.24*	Div'd Decl'd per sh B ■ †	*1.30*
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	3.12	3.29	1.92	*3.15*	*3.60*	Cap'l Spending per sh	*6.00*
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	15.35	15.58	15.67	*15.85*	*16.05*	Book Value per sh C	*18.00*
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	90.52	92.52	94.69	*96.00*	*96.00*	Common Shs Outst'g D	*108.00*
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	23.2	19.8	18.6	*Bold figures are*		Avg Ann'l P/E Ratio	*12.0*
.90	.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	1.15	1.40	1.32	1.18	*Value Line*		Relative P/E Ratio	*.80*
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%	5.0%	6.9%	5.5%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $1440.0 mill. **Due in 5 Yrs** $300.9 mill.
LT Debt $1382.5 mill. **LT Interest** $76.0 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.2x)
Pension Assets-12/10 $832.4 mill.
Oblig. $1.17 bill.
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 95,877,918 shs.
as of 7/21/11
MARKET CAP: $2.4 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
1727.3	1653.7	1781.3	1924.1	2215.6	2460.9	2536.4	3218.9	2309.6	2665.0	*3100*	*3450*	Revenues ($mill)	*4350*
109.8	120.2	120.1	109.6	120.3	109.9	93.6	92.2	84.9	115.4	*125*	*140*	Net Profit ($mill)	*210*
34.6%	34.6%	34.9%	45.8%	36.4%	36.5%	35.4%	34.7%	34.1%	37.0%	*35.0%*	*35.0%*	Income Tax Rate	*32.0%*
5.9%	4.8%	5.1%	7.6%	5.9%	8.4%	8.3%	14.2%	20.6%	7.4%	*6.0%*	*8.0%*	AFUDC % to Net Profit	*26.0%*
56.9%	52.0%	48.6%	47.6%	45.2%	49.9%	47.6%	46.0%	48.0%	44.5%	*45.0%*	*46.5%*	Long-Term Debt Ratio	*46.0%*
41.6%	46.5%	49.8%	51.0%	53.3%	48.6%	51.0%	52.7%	50.7%	54.3%	*53.5%*	*52.5%*	Common Equity Ratio	*53.0%*
2235.8	2251.0	2186.9	2375.1	2283.9	2252.7	2501.8	2635.2	2840.8	2732.9	*2840*	*2945*	Total Capital ($mill)	*3700*
2067.5	2079.3	2311.9	2422.3	2542.8	2647.5	2743.4	2907.4	3088.6	3165.9	*3295*	*3465*	Net Plant ($mill)	*4500*
6.7%	7.3%	7.3%	6.0%	6.8%	6.4%	5.2%	4.7%	4.3%	5.6%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.0%*
11.4%	11.1%	10.7%	8.8%	9.6%	9.7%	7.1%	6.5%	5.8%	7.6%	*8.0%*	*9.0%*	Return on Shr. Equity	*10.5%*
11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	7.2%	6.5%	5.8%	7.7%	*8.0%*	*9.0%*	Return on Com Equity E	*10.5%*
4.4%	4.3%	3.9%	1.1%	1.5%	.7%	.8%	.5%	NMF	1.4%	*.5%*	*1.5%*	Retained to Com Eq	*3.5%*
63%	63%	64%	87%	85%	93%	89%	93%	NMF	82%	*95%*	*86%*	All Div'ds to Net Prof F	*67%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.8	-2.5	-1.1
Avg. Indust. Use (MWH)	6623	6403	6352
Avg. Indust. Revs. per KWH (¢)	25.36	17.68	21.41
Capacity at Yearend (Mw)	2227	2347	2325
Peak Load, Winter (Mw)	1590	1618	1562
Annual Load Factor (%)	75.3	72.2	73.9
% Change Customers (yr-end)	+.1	+.5	+.5
Fixed Charge Cov. (%)	255	234	300

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '08-'10 to '14-'16**
Revenues	2.0%	3.5%	*5.5%*
"Cash Flow"	-1.5%	-3.5%	*5.5%*
Earnings	-2.5%	-6.0%	*11.0%*
Dividends	--	--	*1.0%*
Book Value	2.0%	1.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	729.6	774.1	915.4	799.8	3218.9
2009	543.8	525.9	620.3	619.6	2309.6
2010	619.0	655.7	694.6	695.7	2665.0
2011	710.6	794.3	*795.1*	*800*	*3100*
2012	*825*	*850*	*875*	*900*	*3450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.41	.06	.44	.16	1.07
2009	.22	.17	.37	.15	.91
2010	.29	.31	.35	.26	1.21
2011	.30	.28	*.37*	*.35*	*1.30*
2012	*.35*	*.35*	*.40*	*.35*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.31	.31	.31	.31	1.24
2008	.31	.31	.31	.31	1.24
2009	.31	.31	.31	.31	1.24
2010	.31	.31	.31	.31	1.24
2011	.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 446,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Disc. int'l power sub. in '01. Elec. rev. breakdown: res'l, 33%; comm'l, 34%; large light & power, 32%; other, 1%. Generating sources: oil, 60%; purchased, 40%. Fuel costs: 54% of revs. '10 reported depr. rate (util.): 3.5%. Has 3,400 empls. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 900 Richards St., P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

Hawaiian Electric Industries is trying to narrow the gap between its utilities' allowed and earned returns on equity. In recent years, the allowed returns on equity of HEI's three utilities have been 10% or higher. The utilities haven't come close to earning their allowed ROEs due to rising expenses and declining kilowatt-hour sales that resulted from the weak economy and energy efficiency measures. For the 12 months that ended on June 30th, their combined ROE was just 5.81%. So, the company proposed regulatory mechanisms that decouple electric revenues and electric volume and provide for annual rate adjustments for capital spending and higher operating and maintenance expenses. HEI's largest utility, Hawaiian Electric Company (HECO), has already been granted these mechanisms (and is benefiting from an interim rate hike of $53.2 million), but the annual adjustments will occur on June 1st, not at the start of the year. This will make it harder for HECO to accomplish its target of earning an ROE that is within one percentage point of its allowed ROE of 10% in 2012.

Maui Electric Company (MECO) has filed a rate case, and Hawaii Electric Light Company (HELCO) will follow suit in 2012. MECO is seeking a tariff hike of $27.5 million (6.7%), based on a return of 11% on a 56.85% common-equity ratio. Once MECO and HELCO receive interim rate orders, they will begin to benefit from the same regulatory mechanisms under which HECO now operates.

The new regulatory mechanisms should boost the company's earning potential. Another benefit to the bottom line is the improved return on assets at American Savings Bank. However, it appears as if the earnings recovery will come more slowly than we had anticipated, so we have cut our 2011 and 2012 share-earnings estimates by $0.10 and $0.05, respectively.

We are not enthusiastic about these shares. Despite the lack of dividend growth for more than a decade—and the likelihood of no increase for a few more years—the yield is less than one percentage point above the utility average. That is not an attractive valuation, in our view.

Paul E. Debbas, CFA *November 4, 2011*

(A) Dil. EPS. Excl. gains (losses) from disc. ops.: '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due mid-Feb. (B) Div'ds histor. paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '10: $5.92/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '11: HECO, 10%; in '07: HELCO, 10.7%; in '07: MECO, 10.7%; earned on avg. com. eq., '10: 7.7%. Regul. Climate: Avg. (F) Excl. div'ds paid through reinv. plan.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	20
Earnings Predictability	70

IDACORP, INC. NYSE-IDA

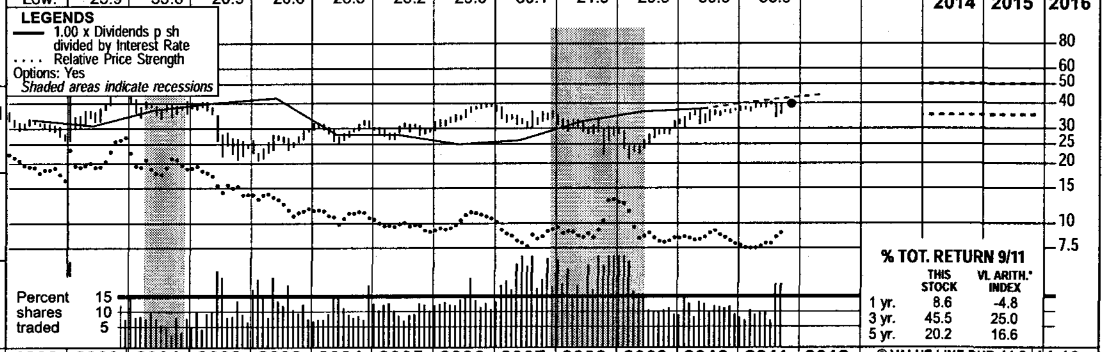
RECENT PRICE	39.83	P/E RATIO	12.8 (Trailing: 14.2; Median: 15.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS 3 Lowered 5/14/10
SAFETY 3 Lowered 2/14/03
TECHNICAL 3 Lowered 8/12/11
BETA .70 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	53.0	49.4	41.0	30.2	32.9	32.1	40.2	39.2	35.1	32.8	37.8	40.7
Low:	25.9	33.6	20.9	20.6	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9

Target Price Range
2014 | 2015 | 2016

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	35	(-10%)	Nil

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	1	0	0	0
Options	3	0	0	0	0	0	0	0	0
to Sell	4	0	1	3	0	1	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	89	70	62
to Sell	70	91	81
Hld's(000)	33237	34091	34537

Percent shares traded 15 10 5

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.6	-4.8
3 yr.	45.5	25.0
5 yr.	20.2	16.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
14.51	15.38	19.90	29.83	17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	**22.00**	**23.75**	Revenues per sh	**24.50**
3.89	4.05	4.22	4.69	4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	**5.55**	**5.55**	"Cash Flow" per sh	**6.15**
2.10	2.21	2.32	2.37	2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	**3.10**	**3.05**	Earnings per sh A	**3.30**
1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	**1.20**	**1.20**	Div'd Decl'd per sh B† ■	**1.50**
2.23	2.49	2.51	2.37	2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	**6.50**	**6.00**	Cap'l Spending per sh	**6.70**
18.15	18.47	18.93	19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	**32.50**	**33.65**	Book Value per sh C	**39.20**
37.61	37.61	37.61	37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	**50.00**	**50.50**	Common Shs Outst'g D	**51.00**
12.4	13.7	13.6	14.4	12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**13.0**
.83	.86	.78	.75	.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.76	*estimates*		Relative P/E Ratio	**.85**
7.2%	6.1%	5.9%	5.4%	6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%			Avg Ann'l Div'd Yield	**3.6%**

CAPITAL STRUCTURE as of 6/30/11
Total Debt $1489.0 mill. Due in 5 Yrs $295.0 mill.
LT Debt $1487.3 mill. LT Interest $75.0 mill.
(LT interest earned: 3.0x)

Pension Assets-12/10 $397.0 mill. Oblig. $569.9 mill.

Pfd Stock None

Common Stock 49,711,638 shs. as of 7/29/11

MARKET CAP: $2.0 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
5648.0	928.8	782.7	844.5	859.5	926.3	879.4	960.4	1049.8	1036.0	**1100**	**1200**	Revenues ($mill)	**1250**
130.0	66.3	40.1	77.8	63.7	100.1	82.3	98.4	124.4	142.5	**155**	**155**	Net Profit ($mill)	**170**
33.3%	--	--	--	16.9%	13.3%	14.3%	16.3%	15.2%	NMF	**15.0%**	**30.0%**	Income Tax Rate	**30.0%**
3.1%	3.0%	7.5%	3.9%	4.7%	4.0%	9.7%	--	--	--	**Nil**	**Nil**	AFUDC % to Net Profit	**Nil**
46.4%	49.2%	50.8%	49.3%	50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	**47.0%**	**47.0%**	Long-Term Debt Ratio	**49.0%**
47.9%	47.9%	46.4%	50.7%	50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	**53.0%**	**53.0%**	Common Equity Ratio	**51.0%**
1818.0	1826.9	1862.5	1987.8	2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	**3045**	**3200**	Total Capital ($mill)	**3900**
1886.0	1906.5	2088.3	2209.5	2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	**3250**	**3400**	Net Plant ($mill)	**4050**
8.7%	5.1%	3.7%	5.3%	4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	**6.0%**	**6.0%**	Return on Total Cap'l	**5.5%**
13.3%	7.1%	4.4%	7.7%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	**9.5%**	**9.0%**	Return on Shr. Equity	**8.5%**
14.4%	7.0%	4.2%	7.2%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	**9.5%**	**9.0%**	Return on Com Equity E	**8.5%**
6.3%	NMF	NMF	2.7%	1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	**6.0%**	**5.5%**	Retained to Com Eq	**4.5%**
58%	113%	NMF	65%	80%	51%	64%	55%	46%	41%	**39%**	**39%**	All Div'ds to Net Prof	**45%**

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+.1	-4.1	-3.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	3.65	4.51	4.50
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3214	3014	2714
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+1.6	+.6	+.4
Fixed Charge Cov. (%)	261	280	278

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-1.5%	1.0%	*2.5%*
"Cash Flow"	--	5.0%	*4.0%*
Earnings	-.5%	11.0%	*4.0%*
Dividends	-4.5%	-2.5%	*4.0%*
Book Value	3.5%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	213.4	230.2	299.7	217.1	960.4
2009	228.6	243.6	324.5	253.1	1049.8
2010	252.5	241.8	309.4	232.3	1036.0
2011	251.1	235.0	***345***	***268.9***	***1100***
2012	***285***	***280***	***355***	***280***	***1200***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.48	.39	1.14	.17	2.18
2009	.40	.59	1.16	.49	2.64
2010	.34	.82	1.39	.40	2.95
2011	.60	.42	***1.60***	***.48***	***3.10***
2012	***.60***	***.55***	***1.35***	***.55***	***3.05***

Cal-endar	QUARTERLY DIVIDENDS PAID B† ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.30	.30	.30	.30	1.20
2008	.30	.30	.30	.30	1.20
2009	.30	.30	.30	.30	1.20
2010	.30	.30	.30	.30	1.20
2011	.30	.30	.30		

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that operates 17 hydroelectric generation developments, 2 natural gas-fired plants, and partly owns three coal plants across Idaho, Oregon, Wyoming, and Nevada. Service territory covers 24,000 square miles with estimated population of one million. Sells electricity in Idaho (95% of revenues) and Oregon (5%). Revenue breakdown: residential, 39%; commercial, 22%; industrial, 13%; other, 26%. Fuel and purchased power cost: 30% of '10 revenues; 2010 depreciation rate: 3.0%. Fuel sources: hydro, 51%; thermal, 49%. Has 2,032 employees. Chrmn. & CEO: J. LaMont Kean. Inc.: Idaho. Address: 1221 W. Idaho St., Boise, ID. 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP recently filed a general rate case settlement stipulation. Recall, Idaho Power filed a general rate case back on June 1st requesting an additional $82.6 million in annual revenues. The increase was comprised of approximately $71.3 million related to revenue requirement categories other than net power supply expenses (non-NPSE) and $11.3 million associated with net power supply expenses (NPSE). However, several issues in the case were contested, resulting in IDA filing a settlement stipulation on September 23rd. The stipulation provides for a decrease of $25.8 million of the requested non-NPSE recovery, resulting in a $45.5 million increase in the non-NPSE components. The stipulation also provides that $22.8 million associated with the recovery of NPSE would not be included in base rates, but would instead be eligible for 100% cost recovery through Idaho Power's power cost adjustment mechanism. If approved, it would result in a 4.07% overall increase in the utility's base rate revenues, effective January 1, 2012.

We view the settlement stipulation positively. Although the full amount was denied, IDA still receives nearly two-thirds of its original non-NPSE request, which seems relatively fair given the regulatory environment in Idaho. The utility should be able to earn decent returns in 2012.

Langley Gulch is on pace for a mid-2012 completion. The 300-megawatt natural gas-fired plant will immediately become a foundational piece of IDA's energy portfolio. The company may still need to tap equity markets to shore up financing.

The yield is lacking relative to the industry. Shares of IDA are currently yielding 3.0%, more than one full percentage point below the 4.2% utility group average. Indeed, the payout ratio has been on the decline for the past several years. However, with the steady earnings growth we project out to 2014-2016, we believe directors may be in a position to increase the dividend at some point over this time.

Investors seeking utility exposure may find better options elsewhere within the group. Based on our estimates, total return potential over the 3 to 5-year period is below average by utility standards.

Michael Ratty *November 4, 2011*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Next earnings report due early Nov. (B) Div'ds historically paid in late Feb., late May, late Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '10: $17.12/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '08: 10.5%; earned on avg. system com. eq., '10: 9.3%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	85

INTEGRYS ENERGY NYSE-TEG

RECENT PRICE	48.20	P/E RATIO	14.4 (Trailing: 14.1; Median: 15.0)	RELATIVE P/E RATIO	1.07	DIV'D YLD	5.6%	VALUE LINE

TIMELINESS 3 New 3/26/10

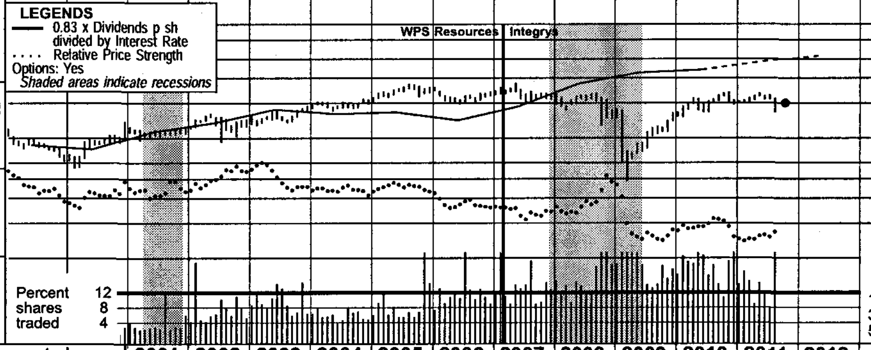
SAFETY 2 Raised 6/24/11

TECHNICAL 3 Lowered 9/16/11

BETA .90 (1.00 = Market)

High:	39.0	36.8	42.7	46.8	50.5	60.0	57.8	60.6	53.9	45.1	54.4	54.0
Low:	22.6	31.0	30.5	36.8	43.5	47.7	47.4	48.1	36.9	19.4	40.5	42.8

Target Price Range
2014 | 2015 | 2016



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2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+15%)	8%
Low	40	(-15%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	0	0	11	4	0	3	0
to Sell	1	0	0	0	0	8	1	4	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	129	115	122
to Sell	147	149	133
Hld's(000)	40518	40134	40346

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.1	19.4
3 yr.	16.2	26.8
5 yr.	30.5	33.1

Integrys Energy Group was created as a holding company on February 21, 2007 to oversee the entire operations of the recently merged WPS Resources and Peoples Energy. WPS acquired *Peoples* in an *agreement* under which each common share of Peoples was converted into .825 share of WPS common. The combination took the new name of Integrys Energy Group. All data on this page prior to 2/21/07 are for WPS Resources only.

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
85.80	83.55	117.07	131.26	173.37	160.01	135.44	184.86	98.71	67.27	***63.20***	***65.15***	Revenues per sh	***73.50***
5.27	5.91	6.23	6.98	7.40	6.33	5.19	4.69	5.34	6.70	***6.65***	***6.95***	"Cash Flow" per sh	***8.00***
2.74	2.74	2.76	4.07	4.09	3.51	2.48	1.58	2.28	3.24	***3.30***	***3.50***	Earnings per sh A	***4.00***
2.08	2.12	2.16	2.20	2.24	2.28	2.56	2.68	2.72	2.72	***2.72***	***2.72***	Div'd Decl'd per sh B ■ †	***2.72***
7.98	7.16	4.77	7.78	10.31	7.94	5.17	7.01	5.85	3.35	***5.40***	***7.60***	Cap'l Spending per sh	***7.75***
22.96	24.45	27.18	29.30	32.47	35.61	42.58	40.79	37.62	37.57	***37.80***	***38.65***	Book Value per sh C	***41.75***
31.18	32.01	36.91	37.26	40.16	43.06	75.99	75.99	75.98	77.35	***78.30***	***78.30***	Common Shs Outst'g D	***78.30***
12.5	14.0	14.9	11.5	13.4	14.7	21.4	30.7	14.8	14.7	*Bold figures are*		Avg Ann'l P/E Ratio	***12.0***
.64	.76	.85	.61	.71	.79	1.14	1.85	.99	.94	*Value Line*		Relative P/E Ratio	***.80***
6.1%	5.5%	5.3%	4.7%	4.1%	4.4%	4.8%	5.5%	8.1%	5.7%	*estimates*		Avg Ann'l Div'd Yield	***5.7%***
2675.5	2674.9	4321.3	4890.6	6962.7	6890.7	10292	14048	7499.8	5203.2	***4950***	***5100***	Revenues ($mill)	***5750***
80.7	94.4	94.5	156.2	157.4	151.6	181.1	124.8	178.2	255.9	***265***	***280***	Net Profit ($mill)	***315***
5.6%	20.8%	26.3%	16.1%	22.9%	22.9%	32.2%	29.1%	41.5%	40.4%	***38.0%***	***38.0%***	Income Tax Rate	***38.0%***
- -	3.2%	2.5%	1.7%	1.0%	.5%	.7%	5.8%	4.5%	.7%	***2.0%***	***2.0%***	AFUDC % to Net Profit	***2.0%***
47.1%	48.3%	45.3%	43.1%	39.0%	44.8%	40.8%	42.1%	45.1%	42.2%	***39.0%***	***39.5%***	Long-Term Debt Ratio	***45.0%***
46.3%	45.8%	52.1%	54.4%	58.7%	53.4%	58.3%	57.0%	53.9%	56.8%	***60.0%***	***59.5%***	Common Equity Ratio	***54.5%***
1544.8	1708.3	1926.2	2008.6	2222.4	2871.9	5552.0	5438.7	5304.4	5118.5	***4920***	***5070***	Total Capital ($mill)	***6025***
1463.6	1610.2	1828.7	2002.6	2049.4	2534.8	4463.8	4773.3	4945.1	5013.4	***5175***	***5510***	Net Plant ($mill)	***6500***
6.8%	7.0%	6.1%	8.8%	8.0%	6.4%	4.5%	3.5%	4.6%	6.2%	***6.5%***	***6.5%***	Return on Total Cap'l	***6.5%***
9.9%	10.7%	9.0%	13.7%	11.6%	9.6%	5.5%	4.0%	6.1%	8.7%	***9.0%***	***9.0%***	Return on Shr. Equity	***9.5%***
10.8%	11.7%	9.1%	14.0%	11.8%	9.7%	5.5%	3.9%	6.1%	8.7%	***9.0%***	***9.0%***	Return on Com Equity E	***9.5%***
2.7%	3.1%	2.0%	6.6%	5.3%	3.4%	- -	NMF	NMF	2.3%	***1.5%***	***2.0%***	Retained to Com Eq	***3.0%***
76%	74%	79%	54%	56%	65%	99%	NMF	118%	74%	***81%***	***77%***	All Div'ds to Net Prof	***69%***

CAPITAL STRUCTURE as of 6/30/11
Total Debt $2340.1 mill. **Due in 5 Yrs** $1000.6 mill.
LT Debt $2131.6 mill. **LT Interest** $119.4 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-12/10 $1.08 bill. **Oblig.** $1.42 bill.
Pfd Stock $51.1 mill. **Pfd Div'd** $3.1 mill.
510,626 shs. 5.00% to 6.88%, callable $101 to $107.50; sinking fund began 11/1/79. All cumulative, $100 par.
Common Stock 78,287,906 shs.
as of 7/28/11
MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.9	-4.3	+3.2
Avg. C & I Use (KWH)	14412	NA	NA
Avg. C & I Revs. per KWH (¢)	7.52	NA	NA
Capacity at Peak (Mw)	NA	3346	3078
Peak Load, Summer (Mw)	2171	2403	2421
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.2	+.4
Fixed Charge Cov. (%)	149	219	314

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	8.5%	-3.5%	*-7.5%*
"Cash Flow"	- -	-4.0%	*6.0%*
Earnings	1.0%	-8.0%	*9.0%*
Dividends	3.0%	4.0%	*Nil*
Book Value	7.0%	5.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	3989	3417	3223	3419	14048
2009	3201	1428	1298	1573	7499.8
2010	1903	1015	998	1287	5203.2
2011	1627	1011	***1012***	***1300***	***4950***
2012	***1650***	***1050***	***1050***	***1350***	***5100***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.77	.31	d.77	.27	1.58
2009	.89	.45	.63	.31	2.28
2010	.95	.82	.56	.91	3.24
2011	1.56	.38	***.51***	***.85***	***3.30***
2012	***1.60***	***.45***	***.55***	***.90***	***3.50***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.5825	.66	.66	.66	2.56
2008	.67	.67	.67	.67	2.68
2009	.68	.68	.68	.68	2.72
2010	.68	.68	.68	.68	2.72
2011	.68	.68	.68		

BUSINESS: Integrys Energy Group, Inc. is a holding company for Wisconsin Public Service, Peoples Gas, and four other utility subsidiaries. Has 491,000 electric customers in WI and MI, 1.7 million gas customers in WI, IL, MN, and MI. Also has retail electric and gas marketing operations in the Northeast and Midwest. Electric revenue breakdown: residential, 29%; small commercial & industrial, 29%; larg commercial & industrial, 19%; other, 23%. Generating sources: coal, 62%; other, 4%; purchased, 34%. Fuel costs: 64% of revenues. '10 deprec. rates (utility): 2.4%-3.6%. Has 4,600 employees. Chairman, President & Chief Executive Officer: Charles A. Schrock. Inc.: WI. Address: 130 East Randolph Street, Chicago, IL 60601. Tel.: 312-228-5400. Internet: www.integrysgroup.com.

Integrys Energy's utilities have five rate cases pending. After a disappointing rate order in Wisconsin took effect in early *2011, Wisconsin* Public Service put forth a "limited reopener" regulatory filing in which the utility sought an electric tariff increase of $32.2 million. A ruling is expected by yearend. In Michigan, Upper Peninsula Power is seeking an electric rate hike of $7.7 million, based on a 10.75% return on equity. The utility will self-implement a rate increase at the start of 2012, and the commission's order is due in mid-2012. On the gas side, the company's two utilities in Illinois are seeking a total increase of $121.8 million, based on a 10.85% ROE. The state commission's staff is recommending a total raise of $46.8 million, based on an ROE of just 8.75%. A ruling is due by mid-January. In Minnesota, the utility is requesting a $15.6 million increase, based on a 10.75% ROE. It is now collecting interim rate relief of $7.5 million (subject to refund). A decision is targeted for the first quarter of 2012.

The utilities' inability to earn their allowed ROEs is an ongoing problem. That's why so many rate cases are pending. Integrys estimates that this shortfall will hurt net profit by $37 million in 2011. (The comparable figure for 2010 was $20.4 million.) Rate relief will narrow the gap, but almost certainly won't *eliminate* it.

Integrys Energy Services isn't experiencing the growth that management expected, following a major restructuring in 2010 that refocused this operation both in product line and geographically. Market conditions haven't been as good as expected for retail energy providers such as Integrys. (Management still likes this business and has no plans to exit it.) Thus, we have cut our 2011 and 2012 share-earnings estimates by $0.10 each year, to $3.30 and $3.50, respectively. Our 2011 estimate is within the company's targeted range of $3.24-$3.44.

This stock's main attraction is its high dividend yield. It is more than one percentage point above the utility mean. However, the stock is already trading within our 2014-2016 Target Price Range, and the lack of dividend growth potential suggests that it has little appeal for the long term.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted EPS. Excl. nonrecur. losses: '09, $3.24; '10, 41¢ net; gains (loss) from discont. ops.: '07, $1.02; '08, 6¢; '09, 4¢; '11 (1¢). Next earnings report due early Nov. (B) Div'ds historically paid mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '10: $27.64/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in WI in '11: 10.3%; in IL in '10: 10.23%-10.33%; earned on avg. com. eq, '10: 8.6%. Regulatory Climate: WI, Above Average; IL, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	40
Earnings Predictability	45

ITC HOLDINGS CORP. NYSE-ITC

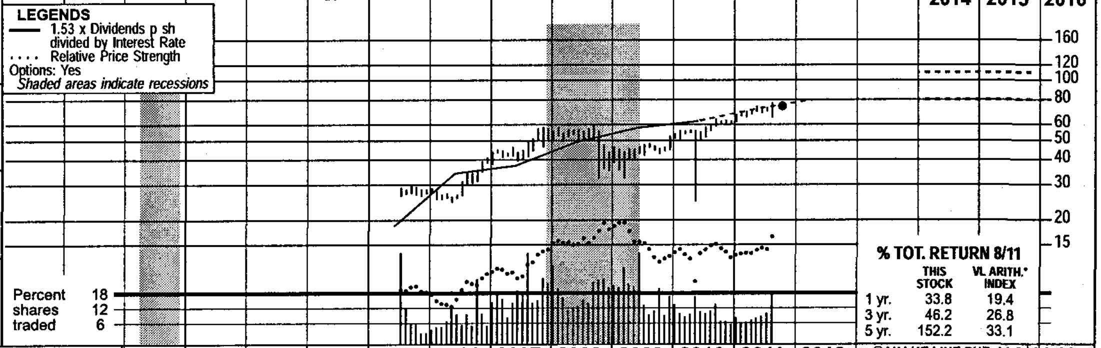
RECENT PRICE	P/E RATIO	(Trailing: 24.0 Median: NMF)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
74.50	21.7		1.62	1.9%	

High:	30.3	41.2	58.6	60.0	52.8	63.9	77.3		
Low:	26.2	24.5	37.9	32.3	32.3	24.7	61.8		

Target Price Range
2014 | 2015 | 2016

TIMELINESS 3 Lowered 12/3/10
SAFETY 2 Raised 6/24/11
TECHNICAL 3 Lowered 9/9/11
BETA .80 (1.00 = Market)

LEGENDS
— 1.53 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+50%)	12%
Low	80	(+5%)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	2	1	0	3	0
to Sell	0	0	0	0	2	1	0	3	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	107	105	106
to Sell	101	103	98
Hld's(000)	45113	45859	46399

Percent shares traded 18 12 6

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.8	19.4
3 yr.	46.2	26.8
5 yr.	152.2	33.1

ITC Holdings was incorporated in the state of Michigan in 2002 for the purpose of acquiring ITC Transmission, which was a subsidiary of The Detroit Edison Company. The acquisition was completed in 2003. ITC Holdings went public on July 26, 2005, via an initial public offering of 12.5 million shares at $23.00 a share. The deal was underwritten by Lehman Brothers, Morgan Stanley, and Credit Suisse First Boston.

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
--	--	--	4.12	6.18	5.27	9.93	12.44	12.40	13.74	*14.35*	*16.30*	Revenues per sh	*22.00*
--	--	--	1.05	2.04	1.73	3.29	4.11	4.33	4.59	*5.05*	*6.05*	"Cash Flow" per sh	*8.75*
--	--	--	.08	1.06	.92	1.68	2.19	2.58	2.84	*3.30*	*3.85*	Earnings per sh A	*5.50*
--	--	--	--	.53	1.08	1.13	1.19	1.25	1.31	*1.38*	*1.43*	Div'd Decl'd per sh B	*1.70*
--	--	--	2.50	3.57	3.95	6.69	8.09	8.08	7.66	*12.80*	*17.35*	Cap'l Spending per sh	*16.50*
--	--	--	6.41	7.92	12.55	13.12	18.71	20.20	22.03	*24.00*	*26.40*	Book Value per sh C	*35.75*
--	--	--	30.68	33.23	42.40	42.92	49.65	50.08	50.72	*52.00*	*52.75*	Common Shs Outst'g D	*55.00*
--	--	--	--	26.3	33.0	27.6	23.2	17.1	20.0	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
--	--	--	--	1.40	1.78	1.47	1.40	1.14	1.28	*Value Line*		Relative P/E Ratio	*1.15*
--	--	--	--	1.9%	3.5%	2.4%	2.3%	2.8%	2.3%	*estimates*		Avg Ann'l Div'd Yield	*1.8%*
--	--	--	126.4	205.3	223.6	426.2	617.9	621.0	696.8	*745*	*860*	Revenues ($mill)	*1215*
--	--	--	2.6	34.7	33.2	73.3	109.2	130.9	145.7	*170*	*205*	Net Profit ($mill)	*315*
--	--	--	39.0%	35.3%	29.2%	33.3%	38.1%	37.2%	36.1%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
--	--	--	80.2%	10.1%	15.0%	14.7%	13.8%	13.1%	11.9%	*15.0%*	*17.0%*	AFUDC % to Net Profit	*11.0%*
--	--	--	71.1%	66.3%	70.3%	72.4%	70.8%	70.6%	69.1%	*68.0%*	*65.0%*	Long-Term Debt Ratio	*65.0%*
--	--	--	28.9%	33.7%	29.7%	27.6%	29.2%	29.4%	30.9%	*32.0%*	*35.0%*	Common Equity Ratio	*35.0%*
--	--	--	680.0	780.6	1794.5	2041.5	3177.3	3445.9	3614.3	*3885*	*4010*	Total Capital ($mill)	*5725*
--	--	--	513.7	603.6	1197.9	1960.4	2304.4	2542.1	2872.3	*3445*	*4245*	Net Plant ($mill)	*6350*
--	--	--	2.3%	6.2%	3.0%	5.7%	5.4%	5.7%	6.1%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
--	--	--	1.3%	13.2%	6.2%	13.0%	11.8%	12.9%	13.0%	*13.5%*	*14.5%*	Return on Shr. Equity	*15.5%*
--	--	--	1.3%	13.2%	6.2%	13.0%	11.8%	12.9%	13.0%	*13.5%*	*14.5%*	Return on Com Equity E	*15.5%*
--	--	--	1.3%	6.5%	NMF	4.5%	5.4%	6.8%	7.1%	*8.0%*	*9.5%*	Retained to Com Eq	*11.0%*
--	--	--	--	50%	115%	66%	54%	48%	45%	*41%*	*37%*	All Div'ds to Net Prof	*30%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $2565.8 mill. **Due in 5 Yrs** $780.4 mill.
LT Debt $2565.8 mill. **LT Interest** $143.7 mill.
(LT interest earned: 2.5x)

Pension Assets-12/10 $24.7 mill. **Oblig.** $45.1 mill.

Pfd Stock None

Common Stock 51,296,413 shs.
as of 7/22/11
MARKET CAP: $3.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	6/30/11
Cash Assets	74.9	95.1	81.2
Receivables	72.3	80.4	93.2
Inventory (FIFO)	36.8	42.3	39.7
Other	110.0	33.9	32.8
Current Assets	294.0	251.7	246.9
Accts Payable	43.5	67.0	98.2
Debt Due	--	--	--
Other	103.2	115.4	144.9
Current Liab.	146.7	182.4	243.1
Fix Chg. Cov.	244%	244%	254%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	--	9.5%
"Cash Flow"	--	--	12.5%
Earnings	--	--	14.0%
Dividends	--	--	5.5%
Book Value	--	--	10.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	141.9	160.6	163.3	152.1	617.9
2009	156.0	157.2	151.3	156.5	621.0
2010	161.3	168.5	178.0	189.0	696.8
2011	179.4	185.1	*190*	*190.5*	*745*
2012	*210*	*215*	*215*	*220*	*860*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.53	.57	.56	.54	2.19
2009	.57	.61	.74	.66	2.58
2010	.67	.71	.75	.71	2.84
2011	.81	.83	*.84*	*.82*	*3.30*
2012	*.94*	*.96*	*.99*	*.96*	*3.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.275	.275	.29	.29	1.13
2008	.29	.29	.305	.305	1.19
2009	.305	.305	.32	.32	1.25
2010	.32	.32	.335	.335	1.31
2011	.335	.335	.3525		

BUSINESS: ITC Holdings Corp. engages in the transmission of electricity in the United States. The company operates primarily as a conduit, moving power from generators to local distribution systems either through its own system or in conjunction with neighboring transmission systems. Acquired Michigan Electric Transmission Company 10/06; Interstate Power & Light's transmission assets 12/07. Has assets in Michigan, Iowa, Minnesota, Illinois, Missouri, and Kansas. Operations are regulated by the Federal Energy Regulatory Commission (FERC). '10 reported depreciation rate: 2.4%. Has about 400 employees. Chairman, President & CEO: Joseph L. Welch. Inc.: Michigan. Address: 27175 Energy Way, Novi, Michigan 48377. Tel.: 248-946-3000. Internet: www.itctransco.com.

ITC Holdings is not like other electric utilities. It is the sole publicly traded transmission-only company. The company operates under a formula-based ratemaking system that accounts for expected capital spending and increases in operating expenses. (Certain costs, such as developmental expenses, are not reflected in the formula.) ITC's four subsidiaries are allowed very healthy returns on equity of 12.16% to 13.88%. As the statistical array above shows, earnings have risen rapidly since 2007. Profits should continue to advance as the company's growing capital budget is reflected in rates. With the release of second-quarter results, management raised its 2011 earnings target by a nickel a share, to $3.25-$3.35. We are sticking with our estimate of $3.30, which is at the midpoint of this range. Our 2012 forecast remains $3.85 a share.

The company has plenty of opportunities to invest capital. A good deal of maintenance capital spending is necessary, especially at one subsidiary, ITC Midwest, which has an aging system that is in the bottom quartile in sustained outages. (Two other ITC subsidiaries are in the top docile.) The company also builds transmission that is needed for renewable projects. Finally, the company's newest unit, ITC Great Plains, has three projects, which are on budget and on schedule, that will expand transmission capacity in Kansas, Nebraska, and Oklahoma. ITC Great Plains plans to spend $517 million on these projects from 2011 through 2015.

The board of directors raised the dividend last month. The hike was $0.07 a share (5.2%) annually, which is within ITC's goal of 4%-5% yearly growth in the disbursement. Even after the increase, however, the yield is not just low for a utility, but is below the median of all dividend-paying stocks under our coverage. Unlike for the typical utility issue, investors focus more on total return than on just dividends.

We have a neutral opinion of ITC stock. The company's solid performance and good prospects have not gone unnoticed. The stock is up 20% this year. At the current quotation, it doesn't stand out for either the year ahead or the 3- to 5-year period.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted earnings. Quarterly earnings don't add to full-year total in '08 due to rounding. Next earnings report due late October.
(B) Quarterly dividend initiated 9/16/05. Dividends historically paid in early March, June, September, and December.
(C) Includes intangibles. In '10: $1.2 billion, $22.91/sh. (D) In millions.
(E) Rates allowed on common equity: 12.16%-13.88%. Earned on avg. common equity, '10: 13.5%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	85
Earnings Predictability	55

PEPCO HOLDINGS NYSE-POM

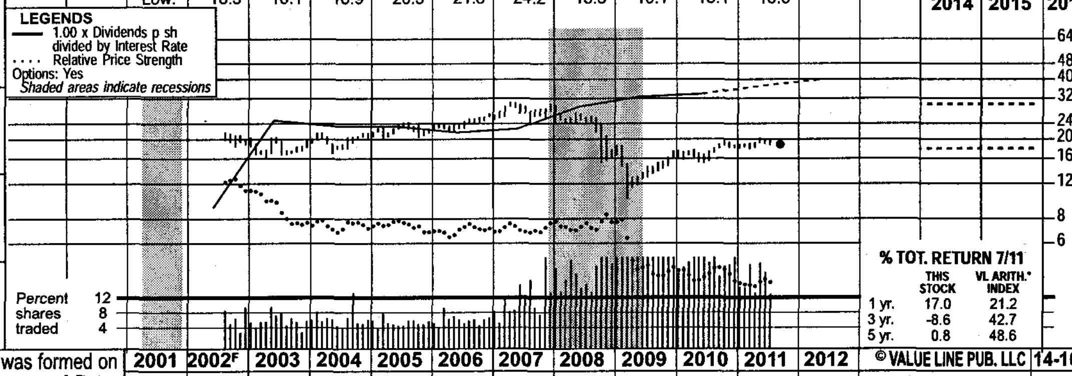
RECENT PRICE	18.86	P/E RATIO	15.3 (Trailing: 12.9 / Median: NMF)	RELATIVE P/E RATIO	1.13	DIV'D YLD	5.7%	VALUE LINE

TIMELINESS 3 Raised 2/5/10
SAFETY 3 Lowered 6/6/03
TECHNICAL 2 Raised 7/29/11
BETA .80 (1.00 = Market)

High:	21.9	20.6	21.7	24.5	27.0	30.7	29.6	18.7	19.8	20.4
Low:	18.3	16.1	16.9	20.3	21.8	24.2	15.3	10.1	15.1	16.6

Target Price Range

2014	2015	2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+60%)	16%
Low	18	(-5%)	5%

Insider Decisions

	S	O	N	D	J	F	M	A	M
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	0	0	0	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	150	161	152
to Sell	119	132	134
Hld's(000)	125477	115863	125507

% TOT. RETURN 7/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.0	21.2
3 yr.	-8.6	42.7
5 yr.	0.8	48.6

Pepco Holdings, Inc. (PHI) was formed on August 1, 2002, upon the merger of Potomac Electric Power Co. (PEPCO) and Conectiv. In the $2.2 billion deal, PEPCO common stockholders received one common share in PHI for each of their shares, and Conectiv investors exchanged each of their common shares for $25 worth of PHI stock and cash, prorated 50/50.

2001	2002F	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
50.20	41.11	42.33	38.35	42.49	43.57	46.71	48.88	41.66	31.27	*29.50*	*27.25*	Revenues per sh	*28.00*
4.87	3.12	3.80	3.71	3.67	3.47	3.30	3.55	2.82	2.97	*3.00*	*3.00*	"Cash Flow" per sh	*3.65*
2.16	1.79	1.35	1.46	1.49	1.33	1.53	1.93	1.06	1.24	*1.25*	*1.25*	Earnings per sh A	*1.65*
--	.42	1.00	1.00	1.00	1.04	1.04	1.08	1.08	1.08	*1.08*	*1.08*	Div'd Decl'd per sh B ■	*1.16*
5.35	3.06	3.48	2.75	2.46	2.47	3.11	3.57	3.89	3.56	*4.40*	*4.60*	Cap'l Spending per sh	*4.00*
18.41	18.17	17.48	17.87	18.88	18.82	20.04	19.14	19.15	18.79	*19.00*	*20.00*	Book Value per sh C	*21.20*
158.70	164.85	171.77	188.33	189.82	191.93	200.51	218.91	222.27	225.08	*227.00*	*235.00*	Common Shs Outst'g D	*250.00*
--	11.3	13.4	13.6	14.9	18.1	18.2	12.2	13.7	14.0	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	.62	.76	.72	.79	.98	.97	.73	.91	.90	*Value Line*		Relative P/E Ratio	*.95*
--	2.1%	5.5%	5.0%	4.5%	4.3%	3.7%	4.6%	7.4%	6.2%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*
7966.5	6777.3	7271.3	7221.8	8065.5	8362.9	9366.4	10700	9259.0	7039.0	*6700*	*6400*	Revenues ($mill)	*7000*
368.0	294.9	245.2	261.3	277.4	254.4	296.5	400.0	235.0	276.0	*285*	*290*	Net Profit ($mill)	*410*
36.8%	17.0%	18.3%	38.7%	38.8%	39.1%	39.3%	29.6%	31.9%	18.8%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
4.5%	--	--	--	--	--	--	--	--	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
53.1%	58.7%	63.1%	59.7%	57.1%	54.6%	54.1%	56.2%	53.8%	49.0%	*48.0%*	*48.5%*	Long-Term Debt Ratio	*48.0%*
41.0%	36.4%	35.6%	39.6%	42.3%	45.1%	45.9%	43.8%	46.2%	51.0%	*52.0%*	*51.5%*	Common Equity Ratio	*52.0%*
7123.0	8228.9	8439.3	8494.0	8469.3	8004.0	8753.0	9568.0	9203.0	8292.0	*8300*	*9100*	Total Capital ($mill)	*10200*
6352.0	6798.0	6964.9	7088.0	7312.0	7576.6	7876.7	8314.0	8863.0	7673.0	*7700*	*7750*	Net Plant ($mill)	*8000*
6.8%	4.6%	4.8%	5.0%	5.0%	5.1%	5.1%	5.8%	4.5%	5.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*7.0%*
11.0%	8.7%	7.9%	7.6%	7.6%	7.0%	7.4%	9.5%	5.5%	6.5%	*6.5%*	*6.0%*	Return on Shr. Equity	*7.5%*
12.6%	9.2%	7.7%	7.7%	7.7%	7.0%	7.4%	9.5%	5.5%	6.5%	*6.5%*	*6.0%*	Return on Com Equity E	*7.5%*
12.6%	5.3%	2.0%	2.5%	2.4%	1.5%	2.3%	4.2%	NMF	.8%	*1.0%*	*1.0%*	Retained to Com Eq	*2.5%*
--	46%	75%	68%	69%	78%	68%	56%	101%	87%	*8.5%*	*88%*	All Div'ds to Net Prof	*71%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $4205 mill. **Due in 5 Yrs** $1450 mill.
LT Debt $3795 mill. **LT Interest** $300 mill.
(LT interest earned: 2.0x)

Pension Assets-12/10 $1.6 bill. **Oblig.** $2.0 bill.

Pfd Stock None

Common Stock 225,395,875 shs.
as of 7/31/11

MARKET CAP: $4.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.6	-2.5	+4.1
Avg. Resid'l Use (KWH)	10503	10395	11253
Avg. Resid'l Revs. per KWH(¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	4606	4647	N/A
Peak Load, Summer (Mw)	N/A	N/A	N/A
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	Nil	+.6	+1.1
Fixed Charge Cov. (%)	263	188	204

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-1.0%	--	*NMF*
"Cash Flow"	-3.5%	-3.5%	*2.5%*
Earnings	-.5%	-.5%	*2.5%*
Dividends	--	1.5%	*1.0%*
Book Value	.5%	1.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	2640	2518	3059	2481	10700
2009	2520	2065	2539	2135	9259
2010	1819	1636	2067	1517	7039
2011	1634	1409	*2000*	*1657*	*6700*
2012	*1600*	*1500*	*1800*	*1500*	*6400*

Cal-endar	EARNINGS PER SHARE A G Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.49	.53	.59	.32	1.93
2009	.21	.11	.56	.18	1.06
2010	.16	.34	.52	.25	1.24
2011	.27	.42	*.41*	*.15*	*1.25*
2012	*.25*	*.30*	*.45*	*.25*	*1.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.26	.26	.26	.26	1.04
2008	.27	.27	.27	.27	1.08
2009	.27	.27	.27	.27	1.08
2010	.27	.27	.27	.27	1.08
2011	.27	.27			

BUSINESS: Pepco Holdings, Inc. consists mainly of three electric utility subsidiaries: Potomac Electric Power Co., serving Washington, D.C. and adjoining areas of Maryland; Delmarva Power, which serves the peninsula area of Delaware, Maryland and Virginia; and Atlantic City Electric, serving southern New Jersey. In July 2010, Pepco sold competitive energy business (Conectiv Energy) to Calpine Corp. Electricity customers: 1.8 million; gas customers: 123,000. Electricity breakdown: residential, 30%; commercial, 49%; other, 21%. 2010 depreciation rate: 2.6%. Has approximately 5,014 employees as of 12/31/10. Chrmn., Pres. & CEO: Joseph M. Rigby. Inc.: DE. Address: 701 Ninth Street, N.W., Wash., D.C. 20068. Telephone.: 202-872-2000. Internet: www.pepcoholdings.com.

We have raised our 2011 earnings estimate for Pepco Holdings. The Washington, DC-based utility reported second-quarter earnings of $0.42 a share, easily surpassing our estimate of $0.25. The beat can be attributed to better-than-expected power delivery earnings, reasonable regulatory treatment, and an income tax adjustment. The company realized a tax benefit of $17 million ($0.08 a share) in the quarter stemming from a resolution with the IRS related to a previous settlement. All told, we have added a nickel to our full-year earnings estimate, now $1.25 a share. Management reaffirmed its guidance of $1.10-$1.25, noting the result would likely come in at the upper end of the range.

Maryland regulators approved a settlement agreement in Delmarva Power's electric base rate case. The Maryland Commission granted an annual rate increase of $12 million, or 1.4%, effective July 8th. Although the return on equity was not specified, an ROE of 10% was authorized for purposes of calculating the allowance for funds used under construction and regulatory asset carrying charges. In our view, the 10% ROE will likely be representative of the actual figure. The commission also established a group that will explore methods to address regulatory lag issues.

The MAPP transmission project may experience further delays. The PJM's power needs assessment for the project is still ongoing with a completed evaluation expected by the end of August. Although Pepco believes MAPP will be needed eventually, it thinks that it is going to be pushed back further than the original June, 2015 in-service date (which management indicated could be several years). Any sort of delay will likely have a negative impact on our long-term earnings outlook, and also result in a restructuring of the company's five-year construction expenditure forecast.

This neutrally ranked stock offers one of the highest yields in the industry. Shares of POM are currently yielding an attractive 5.7%, well above the utility mean of 4.4%. Income-oriented investors may want to consider taking a position here.

Michael Ratty *August 26, 2011*

(A) Based on dil. shs. Excl. nonrecur. items: '01, 30¢; '03, d69¢; '04, 1¢; '05, 47¢; '06, d1¢; '08, 46¢; '10, 62¢. Next egs rpt early Nov. (B) Div'ds paid in late March, June, Sep., and Dec. ■ Div'd reinvest. plan. (C) Incl. def'd chgs: '09, $2.6 bill. or $11.70/sh. (D) In mill. (E) Rate allowed in MD: 9.83% ('10-Pepco), 10.0% ('09-Delmarva); DC: 9.6% ('10-Pep.); DEL: 10.0% ('06-Del.); NJ: 10.3% ('10-ACE); Earned on '10 avg. com. eq., 6.5%. Reg. Clim.: Avg. (F) Pre-'03 results pro forma. (G) Qtrly egs. may not add due to chng. in shs.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	70

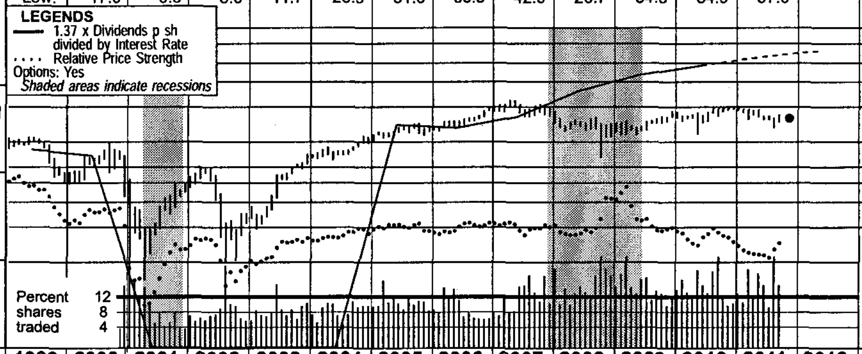
PG&E CORP. NYSE-PCG

RECENT PRICE	42.22	P/E RATIO	14.1 (Trailing: 15.6 / Median: 14.0)	RELATIVE P/E RATIO	1.00	DIV'D YLD	4.3%	VALUE LINE

TIMELINESS **2** Raised 9/2/11
SAFETY **2** Raised 5/12/06
TECHNICAL **2** Raised 10/14/11
BETA .55 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	31.8	20.9	23.8	28.0	34.5	40.1	48.2	52.2	45.7	45.8	48.6	48.0
Low:	17.0	6.5	8.0	11.7	25.9	31.8	36.3	42.6	26.7	34.5	34.9	37.6

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	11%
Low	40	(-5%)	4%

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	2	0	1	0	0	1
to Sell	0	0	0	10	0	1	0	0	1

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	215	190	194
to Sell	190	221	211
Hld's(000)	265396	272189	281663

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.9	-4.8
3 yr.	27.9	25.0
5 yr.	23.1	16.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
23.24	23.82	36.87	52.12	57.74	67.75	63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	*36.30*	*36.90*	Revenues per sh	*44.75*
6.31	5.24	5.98	6.08	7.15	.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	*8.45*	*9.25*	"Cash Flow" per sh	*10.75*
2.95	2.16	1.57	1.88	2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	*2.75*	*3.55*	Earnings per sh A	*4.25*
1.96	1.77	1.20	1.20	1.20	1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	1.82	*1.82*	*1.82*	Div'd Decl'd per sh B ■ †	*2.20*
2.25	3.05	4.36	4.23	4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	*9.90*	*10.95*	Cap'l Spending per sh	*12.25*
20.77	20.73	21.30	21.08	19.10	8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	*29.80*	*32.00*	Book Value per sh C	*38.00*
414.03	403.50	417.67	382.60	360.59	387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	*405.00*	*420.00*	Common Shs Outst'g D	*425.00*
9.4	10.9	15.5	16.8	13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	*Bold figures are*		Avg Ann'l P/E Ratio	*11.5*
.63	.68	.89	.87	.75	--	.25	--	.54	.73	.82	.80	.89	.73	.87	1.01	*Value Line*		Relative P/E Ratio	*.75*
7.1%	7.5%	4.9%	3.8%	4.1%	4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $13362 mill. **Due in 5 yrs** $3646 mill.
LT Debt $11689 mill. **LT Interest** $617.0 mill.
Incl. $223.0 mill. Energy Recovery Bonds.
(LT interest earned: 3.3x)
Pension Assets-12/10 *$10.3 bill.* ***Oblig.*** *$12.1 bill.*
Pfd Stock $252.0 mill. **Pfd Div'd** $14.0 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par.
Common Stock 401,657,362 shs.

MARKET CAP: $17 billion (Large Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
22959	12495	10435	11080	11703	12539	13237	14628	13399	13841	*14700*	*15500*	Revenues ($mill)	*19000*
1099.0	d874.0	791.0	901.0	904.0	1005.0	1020.0	1198.0	1168.0	1113.0	*1120*	*1485*	Net Profit ($mill)	*1840*
35.6%	--	36.7%	35.0%	37.6%	35.5%	34.6%	26.2%	31.1%	33.0%	*33.5%*	*33.5%*	Income Tax Rate	*33.5%*
1.6%	--	3.7%	3.6%	5.6%	6.7%	9.4%	9.5%	11.9%	14.4%	*11.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
58.9%	51.5%	42.4%	45.1%	48.3%	51.7%	52.6%	52.2%	51.4%	49.6%	*48.5%*	*47.0%*	Long-Term Debt Ratio	*45.5%*
34.9%	42.8%	53.9%	53.2%	50.0%	46.8%	46.1%	46.5%	47.4%	49.3%	*50.5%*	*52.0%*	Common Equity Ratio	*53.5%*
12399	8438.0	7815.0	16242	14446	16696	18558	20163	21793	22863	*23875*	*25875*	Total Capital ($mill)	*30200*
19167	16928	18107	18989	19955	21785	23656	26261	28892	31449	*33125*	*35300*	Net Plant ($mill)	*42400*
13.3%	NMF	16.3%	7.6%	8.1%	7.6%	7.4%	7.8%	6.7%	6.2%	*6.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
21.5%	NMF	17.6%	10.1%	12.1%	12.5%	11.6%	12.4%	11.0%	9.6%	*9.0%*	*11.0%*	Return on Shr. Equity	*11.5%*
22.9%	NMF	18.5%	10.3%	12.3%	12.7%	11.8%	12.6%	11.2%	9.7%	*9.0%*	*11.0%*	Return on Com Equity E	*11.5%*
22.9%	NMF	18.5%	10.3%	7.7%	6.8%	6.0%	6.8%	5.5%	3.9%	*3.0%*	*5.5%*	Retained to Com Eq	*5.5%*
10%	--	2%	1%	39%	47%	50%	47%	52%	61%	*66%*	*51%*	All Div'ds to Net Prof	*52%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+2.3	-2.8	-2.0
Avg. Indust. Use (MWH)	12765	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.67	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.3	+.2	+.5
Fixed Charge Cov. (%)	288	296	303

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.1 million electric and 4.3 million gas customers. Electric revenue breakdown: residential, 40%; commercial, 38%; industrial, 12%; agricultural, 7%; other, 3%. Generating sources: nuclear, 24%; hydro, 13%; gas, 5%; purchased, 58%. Fuel costs: 37% of revenues. '10 reported depreciation rate (utility): 3.4%. Has 19,400 employees. Chairman, President & Chief Executive Officer: Anthony F. Earley, Jr. Incorporated: California. Address: One Market, Spear Tower, Suite 2400, San Francisco, California 94105. Telephone: 415-267-7000. Internet: www.pgecorp.com.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-4.5%	6.0%	*3.0%*
"Cash Flow"	6.0%	7.5%	*4.5%*
Earnings	--	7.0%	*6.0%*
Dividends	3.5%	--	*4.5%*
Book Value	5.5%	10.5%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	3733	3578	3674	3643	14628
2009	3431	3194	3235	3539	13399
2010	3475	3232	3513	3621	13841
2011	3597	3684	*3700*	*3719*	*14700*
2012	*3950*	*3750*	*3850*	*3950*	*15500*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.62	.80	.83	.97	3.22
2009	.65	.87	.80	.71	3.03
2010	.67	.86	.66	.63	2.82
2011	.50	.91	*.75*	*.59*	*2.75*
2012	*.75*	*.95*	*.95*	*.90*	*3.55*

QUARTERLY DIVIDENDS PAID B ■ †

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.33	.36	.36	.36	1.41
2008	.36	.39	.39	.39	1.53
2009	.39	.42	.42	.42	1.65
2010	.42	.455	.455	.455	1.79
2011	.455	.455	.455	.455	

PG&E is incurring sizable costs associated with the explosion in 2010 of its gas pipeline in San Bruno, California. The company's latest estimate of the direct expenses associated with the accident is $413 million (pretax) in 2011. Of this amount, $126 million was recorded in the first half. PG&E is also accruing reserves for potential third-party claims. This amounted to $220 million in 2010, $59 million in the first half of 2011, and will probably be as much as $180 million for the full year. Insurance should cover most of the third-party claims, and the company recovered $60 million in the first half. These costs and insurance recoveries are *included* in our earnings presentation. For 2012, PG&E forecasts direct expenses of $274 million. Its proposed pipeline safety enhancement plan suggests that all but $43 million is recoverable in rates. The plan also includes over $1.4 billion of capital costs from 2011 through 2014. The California Public Utilities Commission (CPUC) must issue a ruling on the plan.

The National Transportation Safety Board's report criticized the company. This was not surprising, and PG&E has acknowledged that changes are in order. The CPUC is conducting its own investigation, and has the authority to fine the utility. We would *exclude* a sizable fine from our earnings presentation.

Another year of weak earnings is likely in 2011, but we look for better results in 2012. The direct expenses associated with the San Bruno accident affect our estimates significantly, and have obviated the benefits of the rate relief that the utility was granted earlier this year. As for the dividend, PG&E has stated that there will be no increase in 2011. We expect no raise next year, as well. Note that PG&E has a new chief executive, Tony Earley (formerly of DTE Energy).

Even after the stock's underperformance since the accident, the yield and 3- to 5-year total return potential are only about average for a utility. The stock's favorable Timeliness rank is due, in part, to the fact that insurance recoveries ($0.09 a share in the June quarter) aren't included in our earnings estimates because the timing and amount of these are impossible to predict.

Paul E. Debbas, CFA — *November 4, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '95, 4¢; '96, (41¢); '97, 18¢; '99, ($2.44); '04, $6.95; '09, 18¢; gain from discontinued ops.: '08, 41¢. Incl. nonrec. loss: '00, $11.83. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '10: $14.79/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '07: 11.35%; earned on avg. com. eq., '10: 10.0%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	90

PORTLAND GENERAL NYSE-POR

RECENT PRICE 24.37 | P/E RATIO 13.7 (Trailing: 11.1 / Median: NMF) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Lowered 8/19/11

SAFETY 3 Lowered 5/7/10

TECHNICAL 3 Lowered 9/9/11

BETA .75 (1.00 = Market)

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+25%)	10%
Low	20	(-20%)	1%

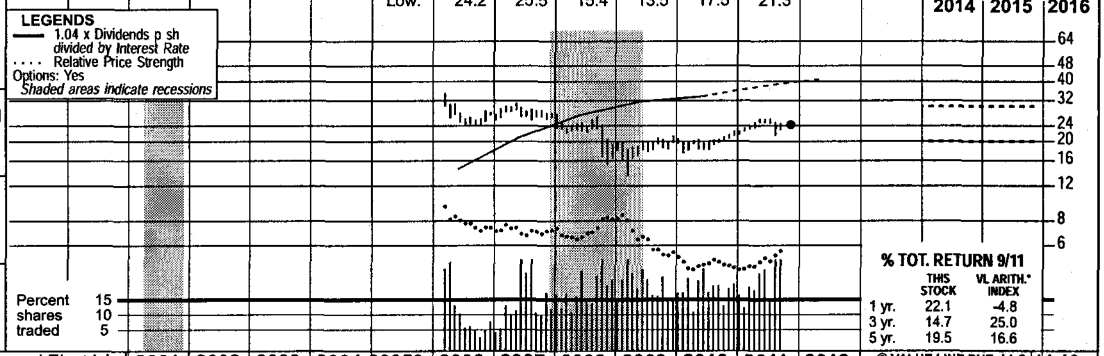
Insider Decisions

	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	0	0	0	0	1	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	110	107	121
to Sell	77	89	104
Hld's(000)	66971	71103	70500

	2005	2006	2007	2008	2009	2010	2011
High:		35.0	31.3	27.7	21.4	22.7	26.0
Low:		24.2	25.5	15.4	13.5	17.5	21.3



% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.1	-4.8
3 yr.	14.7	25.0
5 yr.	19.5	16.6

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2001	2002	2003	2004	2005G	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
--	--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	*24.15*	*25.75*	Revenues per sh	*30.50*
--	--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	*5.00*	*5.25*	"Cash Flow" per sh	*6.00*
--	--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	*2.00*	*2.05*	Earnings per sh A	*2.25*
--	--	--	--	--	.68	.93	.97	1.01	1.04	*1.06*	*1.08*	Div'd Decl'd per sh B ■ †	*1.20*
--	--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	*4.50*	*4.05*	Cap'l Spending per sh	*3.75*
--	--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	*22.05*	*22.95*	Book Value per sh C	*25.75*
--	--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	*75.50*	*75.75*	Common Shs Outst'g D	*76.50*
--	--	--	--	--	23.4	11.9	16.3	14.4	12.0	*Bold figures are*		Avg Ann'l P/E Ratio	*11.0*
--	--	--	--	--	1.26	.63	.98	.96	.76	*Value Line*		Relative P/E Ratio	*.75*
--	--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*
--	--	--	1454.0	1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	*1825*	*1950*	Revenues ($mill)	*2325*
--	--	--	92.0	64.0	71.0	145.0	87.0	95.0	125.0	*150*	*155*	Net Profit ($mill)	*175*
--	--	--	37.0%	40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
--	--	--	9.8%	18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	*7.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
--	--	--	41.1%	42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	*50.5%*	*51.0%*	Long-Term Debt Ratio	*52.0%*
--	--	--	58.9%	57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	*49.5%*	*49.0%*	Common Equity Ratio	*48.0%*
--	--	--	2171.0	2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	*3360*	*3535*	Total Capital ($mill)	*4100*
--	--	--	2275.0	2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	*4250*	*4315*	Net Plant ($mill)	*4325*
--	--	--	5.6%	4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
--	--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
--	--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
--	--	--	7.2%	5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
--	--	--	--	--	39%	40%	69%	76%	62%	*53%*	*52%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $1798.0 mill. **Due in 5 Yrs** $333.0 mill.
LT Debt $1798.0 mill. **LT Interest** $104.0 mill.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $10.0 mill.

Pension Assets-12/10 $473.0 mill.
Oblig. $550.0 mill.

Pfd Stock None

Common Stock 75,341,327 shs.
as of 7/29/11

MARKET CAP: $1.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+.7	-3.3	-3.1
Avg. Indust. Use (MWH)	16255	14303	15109
Avg. Indust. Revs. per KWH (¢)	6.42	7.07	6.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	4031	3949	3582
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+.7	+.5

Fixed Charge Cov. (%)	226	179	224

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	1.5%	3.0%
"Cash Flow"	--	-1.0%	5.0%
Earnings	--	7.5%	7.5%
Dividends	--	--	3.0%
Book Value	--	2.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	471.0	425.0	400.0	449.0	1745.0
2009	485.0	389.0	445.0	485.0	1804.0
2010	449.0	415.0	464.0	455.0	1783.0
2011	484.0	411.0	*455*	*475*	*1825*
2012	*525*	*450*	*475*	*500*	*1950*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.44	.63	--	.32	1.39
2009	.47	.31	.43	.11	1.31
2010	.36	.32	.65	.34	1.66
2011	.92	.29	*.44*	*.35*	*2.00*
2012	*.70*	*.40*	*.55*	*.40*	*2.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.225	.225	.235	.235	.92
2008	.235	.245	.245	.245	.97
2009	.245	.245	.255	.255	1.00
2010	.255	.255	.26	.26	1.03
2011	.26	.26	.265	.265	

BUSINESS: Portland General Electric Company (PGE) provides electricity to 825,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 45%; commercial, 34%; industrial, 12%; other, 9%. Generating sources: coal, 23%; gas, 21%; hydro, 9%; wind, 4%; purchased, 43%. Fuel costs: 46% of revenues. '10 reported depreciation rate: 3.9%. Has 2,700 employees. Chairman: Corbin A. McNeill, Jr. Chief Executive Officer and President: Jim Piro. Incorporated: Oregon. Address: 121 SW Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric's earnings are likely to rise substantially this year. The utility is benefiting from a tariff increase that took effect at the start of 2011. The Public Utility Commission of Oregon raised PGE's rates by $65 million (3.9%). The rate order was based on a return of 10% on a common-equity ratio of 50%. Also, hydro conditions in early 2011 were favorable, helping to produce a first-quarter tally that was well above the norm for the period. Second-quarter profits were below our expectation, so we have trimmed our 2011 estimate by a nickel a share, to $2.00. Our revised estimate is still within the company's targeted range of $1.90-$2.05.

We expect little bottom-line improvement in 2012. We base our earnings forecast on normal hydro conditions. At least the service area's economy is showing moderate improvement, aided by a project that Intel is building.

For the time being, capital spending is declining. Last year, PGE completed the third phase of a 450-megawatt wind project, at a total cost of about $1 billion. No major construction is currently under way. In the next few months, however, the company will put forth requests for proposals for additional base-load, peaking, and renewable generating capacity. The outcome should be known in 2012. If PGE winds up building plants instead of entering into purchased-power agreements with other owners, this would raise its capital budget considerably and necessitate some financing, both debt and equity, beginning in 2013. Our capital spending estimates and projections include nothing for these potential projects. Separately, PGE is proposing to build a transmission line at a cost of $800 million-$1 billion. The company is looking for partners for the project, with an estimated in-service date in late 2016 or 2017.

This stock has an average dividend yield for a utility. With the quotation within our 2014-2016 Target Price Range, however, total return potential is unexciting. We believe there is a bit of takeover speculation in the share price, but we do not advise investors to purchase the stock in the hopes that the company will receive a buyout offer.

Paul E. Debbas, CFA *November 4, 2011*

(A) Diluted EPS. '09 & '10 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '10: $7.22/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on common equity in '11: 10.0%; earned on average com. eq., '10: 8.0%. Regulatory Climate: Below Average. (F) Summer peak in '09. (G) '05 per-share data are pro forma, based on shares outstanding when the stock began trading in '06.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	40

PPL CORPORATION NYSE-PPL

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
26.97	11.3	(Trailing: 10.9 / Median: 14.0)	0.83	5.2%	VALUE LINE

TIMELINESS 3 Raised 11/12/10
SAFETY 3 Lowered 11/28/08
TECHNICAL 2 Raised 7/22/11
BETA .65 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	23.1	31.2	20.0	22.2	27.1	33.7	37.3	54.6	55.2	34.4	33.1	28.7
Low:	9.2	15.5	13.0	15.8	19.9	25.5	27.8	34.4	26.8	24.3	23.8	24.1

2014-16 PROJECTIONS

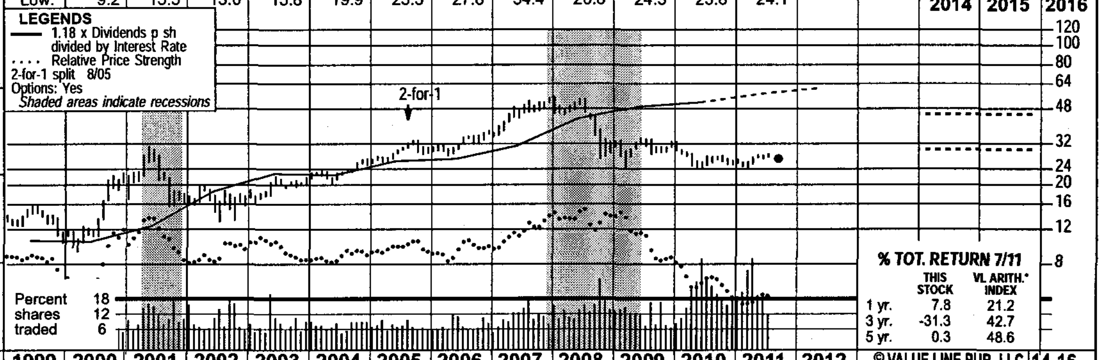
	Price	Gain	Ann'l Total Return
High	45	(+65%)	17%
Low	30	(+10%)	8%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	8	0	1	0	0
to Sell	1	0	0	0	3	0	0	0	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	243	223	231
to Sell	186	194	183
Hld's(000)	334842	314712	309906



1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
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	21.47	20.03	17.63	19.20	20.70	Revenues per sh	20.50
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	4.71	3.47	3.66	3.95	4.35	"Cash Flow" per sh	4.75
.97	1.03	.99	1.12	1.01	1.64	1.79	1.54	1.84	1.87	1.92	2.29	2.63	2.45	1.19	2.29	2.40	2.55	Earnings per sh A	3.00
.84	.84	.84	.67	.50	.53	.53	.72	.77	.82	.96	1.10	1.22	1.34	1.38	1.40	1.40	1.40	Div'd Decl'd per sh B ■	1.70
1.26	1.11	.93	.97	1.11	1.59	2.99	2.74	2.17	1.94	2.13	3.62	4.51	3.79	3.25	3.30	4.85	6.40	Cap'l Spending per sh	5.50
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	13.55	14.57	16.98	19.20	20.40	Book Value per sh C	25.50
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	374.58	377.18	483.39	578.00	580.00	Common Shs Outst'g D	680.00
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	17.6	25.7	11.9	Bold figures are		Avg Ann'l P/E Ratio	13.0
.72	.71	.62	.57	.76	.58	.64	.61	.60	.66	.80	.76	.92	1.06	1.71	.76	Value Line		Relative P/E Ratio	.85
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%	3.1%	4.5%	5.1%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 3/31/11
Total Debt $13630 mill. **Due in 5 Yrs** $4130.0 mill.
LT Debt $12247 mill. **LT Interest** $612.0 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value; 23 mill. units 4.625%, $50 stated value, conv. into com. in 2013.
(LT interest earned: 3.7x)
Leases, Uncapitalized Annual rentals $122.0 mill.
Pension Assets-12/10 $5.34 bill. **Oblig.** $6.85 bill.
Pfd Stock $250.0 mill. **Pfd Div'd** $16.0 mill.
2,500,000 shs. 6.25%, $100 liq. preference, redeemable after 4/6/11.
Common Stock 577,151,364 shs. **as of 4/29/11**
MARKET CAP: $16 billion (Large Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
5725.0	5429.0	5587.0	5812.0	6219.0	6899.0	6498.0	8044.0	7556.0	8521.0	11100	12000	Revenues ($mill)	13900
576.0	536.0	667.0	692.0	739.0	899.0	1031.0	940.0	465.0	1009.0	1355	1495	Net Profit ($mill)	2030
29.7%	25.7%	27.1%	22.8%	14.0%	23.2%	20.7%	31.8%	21.8%	22.0%	35.0%	35.0%	Income Tax Rate	35.0%
4.3%	3.4%	1.2%	.7%	--	--	--	.1%	.2%	.5%	Nil	Nil	AFUDC % to Net Profit	Nil
64.8%	66.5%	71.1%	61.6%	57.5%	55.4%	54.1%	57.1%	55.2%	59.0%	55.0%	52.0%	Long-Term Debt Ratio	43.0%
23.7%	25.1%	28.5%	37.9%	42.0%	42.2%	43.6%	40.5%	42.5%	39.8%	44.0%	47.0%	Common Equity Ratio	56.0%
7845.0	8868.0	11455	11171	10513	12151	12747	12529	12940	20621	25250	25150	Total Capital ($mill)	30800
6135.0	9566.0	10446	11209	10916	12069	12605	12416	13174	20858	27475	30150	Net Plant ($mill)	38600
9.6%	8.8%	7.6%	8.4%	9.3%	9.3%	9.8%	9.2%	5.0%	6.1%	6.5%	7.5%	Return on Total Cap'l	7.5%
20.8%	18.1%	20.2%	16.1%	16.5%	16.6%	17.6%	17.5%	8.0%	11.9%	12.0%	12.5%	Return on Shr. Equity	11.5%
28.2%	21.1%	19.6%	16.3%	16.7%	17.3%	18.2%	18.2%	8.1%	12.0%	12.0%	12.5%	Return on Com Equity E	11.5%
20.2%	12.4%	11.7%	9.3%	8.8%	9.3%	10.0%	8.5%	NMF	5.2%	5.5%	5.5%	Retained to Com Eq	5.0%
35%	49%	43%	43%	47%	47%	46%	54%	115%	58%	56%	55%	All Div'ds to Net Prof	57%

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+.3	-3.5	+15.3
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	7316	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.3	+22.5
Fixed Charge Cov. (%)	367	222	304

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	2.0%	4.5%	.5%
"Cash Flow"	3.5%	1.5%	3.0%
Earnings	4.5%	1.0%	7.0%
Dividends	9.5%	10.0%	3.5%
Book Value	9.5%	7.0%	9.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1526	1024	2981	2513	8044.0
2009	2351	1673	1805	1727	7556.0
2010	3006	1473	2179	1863	8521.0
2011	2910	2489	3051	2650	11100
2012	3400	2600	3200	2800	12000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.65	.50	.55	.74	2.45
2009	.64	.07	.12	.37	1.19
2010	.74	.22	.62	.69	2.29
2011	.82	.35	.60	.63	2.40
2012	.80	.45	.65	.65	2.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.275	.305	.305	.305	1.19
2008	.305	.335	.335	.335	1.31
2009	.335	.345	.345	.345	1.37
2010	.345	.35	.35	.35	1.40
2011	.35	.35	.35		

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to 1.4 mill. customers in eastern & central PA. Acq'd Kentucky *Utilities* and Louisville Gas and Electric (1.2 mill. customers) 11/10. Has subsidiaries in power generation & marketing, electricity distribution in U.K. (7.6 mill. customers). Sold gas distribution subsidiary in '08. Electric rev. breakdown & generating sources not provided. Fuel costs: 44% of revs. '10 reported depr. rates: 2.3%-3.3%. Has 13,800 employees. Chairman & CEO: James H. Miller. President & COO: William H. Spence. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

Predicting PPL Corporation's earnings is harder than usual this year. Just since November of 2010, the company has greatly expanded its regulated utility operations by buying two utilities in Kentucky and one in the United Kingdom. PPL issued a lot of stock in these deals, resulting in a big jump in average shares outstanding. Also, the company is incurring some merger-related expenses, which we *include* in our earnings presentation. Generally, the company's utility operations are performing well, but PPL Electric Utilities in Pennsylvania continues to feel the effects of regulatory lag, despite a rate hike earlier this year. On the other hand, the nonregulated energy-supply business is dealing with low power prices, rising coal costs, and unplanned nuclear outages that will reduce net profit by an estimated $60 million-$65 million this year. Finally, ongoing earnings are affected by mark-to-market accounting gains or losses. These hurt share net by $0.27 in 2010 and helped by a cent in the first half of 2011. We cut our 2011 estimate by $0.15 a share, largely because second-quarter profits fell short of our estimate.

We expect improved earnings in 2012. A full year's income from the U.K. acquisition will help. Also, we assume no nuclear issues beyond the normal expenses associated with the scheduled refueling outage. Our estimate of $2.55 a share would be PPL's best tally since 2007.

The two Kentucky utilities are asking the state commission to approve an expected $2.5 billion in environmental spending for their coal-fired facilities. This spending is needed for compliance with new EPA rules. A decision is expected in late 2011. The utilities would recover these expenditures every two months via a rider on customers' bills. The utilities will earn a return on equity of 10.63% until this spending is rolled into base rates.

PPL stock offers an above-average yield. The board of directors didn't boost the dividend this year, and we forecast no increase in 2012. Even so, we project that dividend growth will resume by the 2014-2016 period. Combined with the rise in earnings that we project over that time, this equity offers better total return potential than the average utility issue.

Paul E. Debbas, CFA *August 26, 2011*

(A) Diluted EPS. Excl. nonrec. losses: '07, 12¢; '10, 8¢; *gains (losses) on disc. ops.*: '05, (12¢); '07, 19¢; '08, 3¢; '09, (10¢); '10, (4¢). '08 & '09 EPS don't add due to rounding, '10 due to chg. in shs. Next earnings report due early Nov. (B) Div'ds histor. paid in early Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '10: $8.01/sh. (D) In mill., adj. for split. (E) Rate base: Fair val. Rate all'd on com. eq. in PA in '08: none spec.; in KY in '10: 9.75%-10.75%; earned on avg. com. eq., '10: 14.0%. Regulat. Climate: Avg. (F) Summer peak in '08.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	60

TECO ENERGY, INC. NYSE-TE

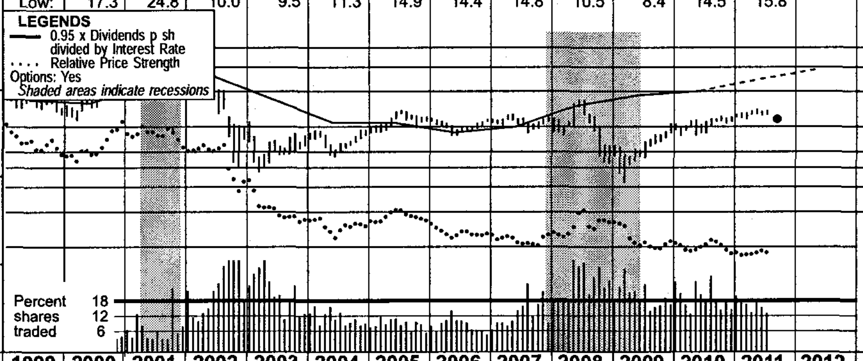
RECENT PRICE 17.48 | P/E RATIO 12.4 (Trailing: 15.6 Median: 15.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS	2	Raised 8/26/11
SAFETY	3	Lowered 3/7/03
TECHNICAL	3	Lowered 7/8/11

BETA .85 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	33.2	33.0	29.0	17.0	15.5	19.3	17.7	18.6	22.0	16.7	18.1	19.7
Low:	17.3	24.8	10.0	9.5	11.3	14.9	14.4	14.8	10.5	8.4	14.5	15.8

LEGENDS
— 0.95 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range 2014 | 2015 | 2016

40 32 24 16 12 10 8 6 4

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+45%)	14%
Low	18	(+5%)	7%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	1	0	0	0	0	2
to Sell	0	0	2	1	0	0	0	0	2

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	160	141	117
to Sell	131	156	181
Hld's(000)	115966	118085	113977

Percent shares traded 18 12 6

% TOT. RETURN 7/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.9	21.2
3 yr.	17.9	42.7
5 yr.	50.4	48.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
11.90	12.53	14.23	14.83	15.01	18.17	18.97	15.22	14.59	13.37	14.46	16.46	16.77	15.85	15.48	16.23	15.75	16.15	Revenues per sh	18.25
3.08	3.28	3.34	3.25	3.28	4.11	4.31	3.20	1.96	2.14	2.37	2.51	2.51	2.01	2.35	2.59	2.80	3.05	"Cash Flow" per sh	3.50
1.60	1.71	1.61	1.52	1.53	1.97	2.24	1.95	d.08	.71	1.00	1.17	1.27	.77	1.00	1.13	1.30	1.45	Earnings per sh A	1.75
1.05	1.11	1.17	1.23	1.29	1.33	1.37	1.41	.93	.76	.76	.76	.78	.80	.80	.82	.85	.89	Div'd Decl'd per sh B ■	1.05
3.70	2.28	1.62	2.24	3.23	5.45	6.92	6.06	3.14	1.37	1.42	2.18	2.34	2.77	2.99	2.28	2.05	2.15	Cap'l Spending per sh	2.00
9.98	10.73	11.04	11.42	10.73	11.93	14.12	14.86	8.93	6.43	7.65	8.25	9.56	9.43	9.75	10.10	10.55	11.15	Book Value per sh C	13.25
116.96	117.60	130.90	132.00	132.10	126.30	139.60	175.80	187.80	199.70	208.20	209.50	210.90	212.90	213.90	214.90	216.00	217.00	Common Shs Outst'g D	220.00
13.8	14.3	15.4	17.8	14.2	11.9	12.9	11.0	--	19.3	17.1	13.8	13.3	21.2	12.6	14.6	Bold figures are	Value Line estimates	Avg Ann'l P/E Ratio	12.5
.92	.90	.89	.93	.81	.77	.66	.60	--	1.02	.91	.75	.71	1.28	.84	.93			Relative P/E Ratio	.85
4.7%	4.5%	4.7%	4.5%	5.9%	5.7%	4.8%	6.6%	7.4%	5.5%	4.4%	4.7%	4.6%	4.9%	6.3%	4.9%			Avg Ann'l Div'd Yield	4.8%

CAPITAL STRUCTURE as of 3/31/11
Total Debt $3148.6 mill. Due in 5 Yrs $924.1 mill.
LT Debt $3070.3 mill. LT Interest $198.0 mill.
(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $17.3 mill.

Pension Assets-12/10 $479.7 mill. Oblig. $610.3 mill.

Pfd Stock None

Common Stock 214,936,829 shs. as of 4/28/11

MARKET CAP: $3.8 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
2648.6	2675.8	2740.0	2669.1	3010.1	3448.1	3536.1	3375.3	3310.5	3487.9	3400	3500	Revenues ($mill)	4000
303.7	298.2	d14.7	137.4	211.0	244.4	265.8	162.4	213.9	242.9	285	325	Net Profit ($mill)	385
--	--	--	38.5%	45.1%	40.4%	40.7%	36.8%	31.6%	34.8%	35.0%	35.0%	Income Tax Rate	35.0%
3.0%	4.4%	--	.7%	.0%	1.6%	2.3%	5.4%	6.5%	1.2%	1.0%	3.0%	AFUDC % to Net Profit	1.0%
48.3%	50.5%	72.4%	75.1%	70.0%	65.0%	61.0%	61.5%	60.6%	59.2%	51.0%	56.0%	Long-Term Debt Ratio	52.5%
51.7%	39.7%	27.6%	24.9%	30.0%	35.0%	39.0%	38.5%	39.4%	40.8%	49.0%	44.0%	Common Equity Ratio	47.5%
3814.1	6585.1	6070.3	5163.9	5300.9	4941.6	5175.4	5214.3	5287.0	5317.8	4635	5515	Total Capital ($mill)	6100
4838.3	5464.0	5679.0	4657.9	4566.9	4766.9	4888.2	5221.3	5544.1	5841.0	5955	6085	Net Plant ($mill)	6225
9.7%	5.7%	2.1%	5.6%	6.5%	7.3%	7.3%	5.1%	6.0%	6.4%	8.5%	7.5%	Return on Total Cap'l	8.0%
15.4%	9.1%	NMF	10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.2%	12.5%	13.5%	Return on Shr. Equity	13.0%
15.4%	9.9%	NMF	10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.2%	12.5%	13.5%	Return on Com Equity E	13.0%
6.1%	3.2%	NMF	NMF	3.3%	5.0%	5.1%	NMF	2.1%	3.1%	4.5%	5.5%	Retained to Com Eq	5.5%
61%	72%	NMF	106%	75%	65%	61%	104%	80%	72%	65%	60%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.8	-1.1	+2.3
Avg. Indust. Use (Mw)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.04	9.63	9.35
Capacity at Peak (Mw)	4477	4719	4684
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.1	-.1	+.6
Fixed Charge Cov. (%)	166	199	270

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	2.5%	2.5%
"Cash Flow"	-4.0%	1.5%	7.0%
Earnings	-5.5%	12.0%	10.5%
Dividends	-4.5%	-.5%	4.5%
Book Value	-1.5%	5.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	791.7	887.2	926.1	770.3	3375.3
2009	824.0	825.2	896.3	765.0	3310.5
2010	912.3	898.8	901.8	775.0	3487.9
2011	796.1	885.7	918.2	800	3400
2012	800	900	950	850	3500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.15	.24	.27	.10	.77
2009	.16	.29	.30	.25	1.00
2010	.26	.35	.35	.17	1.13
2011	.24	.36	.37	.33	1.30
2012	.35	.35	.40	.35	1.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.19	.195	.195	.195	.78
2008	.195	.20	.20	.20	.80
2009	.20	.20	.20	.20	.80
2010	.20	.205	.205	.205	.82
2011	.205	.215	.215		

BUSINESS: TECO Energy, Inc. is a holding company for Tampa Electric, which serves 672,000 customers in west central Florida, and Peoples Gas (acquired 6/97), which serves 336,000 customers in Florida. TECO also mines coal and has generation investments in Guatemala. Sold TECO Transport 12/07. Electric revenue breakdown: residential, 50%; commercial, 30%; industrial, 9%; other, 11%. Generating sources: coal, 53%; gas, 38%; purchased, 9%. Fuel costs: 35% of revenues. '10 reported deprec. rate (utility): 3.6%. Has 4,100 employees. Chairman: Sherrill W. Hudson. President & CEO: John B. Ramil. Incorporated: Florida. Address: TECO Plaza, 702 N. Franklin Street, Tampa, Florida 33602. Telephone: 813-228-1111. Internet: www.tecoenergy.com.

We estimate that TECO Energy's earnings will increase this year. In 2010, the company incurred $0.16 a share of charges for the early retirement of debt. There were no such charges in the first half of 2011, and we expect none in the second half. The refinancings and repayments of debt have lowered TECO's interest expense. Tampa Electric and Peoples Gas are performing well and are likely to earn their allowed returns on equity this year. In fact, the utilities' customer counts have risen for seven consecutive quarters, which suggests that the service area is recovering (albeit slowly) from the housing crisis in Florida. All told, our 2011 earnings estimate is within management's targeted range of $1.25-$1.40 a share.

TECO Coal is experiencing some positive and negative trends. On the positive side, contracted prices are rising, and the proportion of the company's sales that is for higher-priced specialty coal is increasing. Realized prices should get a further boost next year, after a contract for 600,000 tons, which is well below the current market level, expires. This production has been sold at prices that are well above the price in that contract. On the negative side, costs are up, as well, and volume is below management's previous expectation for the year. TECO Coal now expects sales of 8.2 million-8.5 million tons this year, compared with 8.5 million-9.0 million previously. The volume shortfall is due to delays in surface mine permitting and a shortage of contract minors, and the higher price of oil is causing the cost of oil-based equipment, such as tires, to climb. When all is said and done, we believe the pluses will exceed the minuses, and TECO Coal's contribution to the parent's bottom line will increase this year and next.

Earnings should advance solidly in 2012. The aforementioned repricing of an old contract at TECO Coal should be the key factor. We look for modest growth from the utilities, too. Our profit forecast remains at $1.45 a share.

Timely TECO stock offers a dividend yield and 2014-2016 total return potential that are somewhat above the norm for utilities. Moderate dividend growth should occur through the middle of the decade.

Paul E. Debbas, CFA *August 26, 2011*

(A) Dil. earnings. Excl. nonrec. gain (losses): '97, (6¢); '99, (11¢); '03, ($4.97); '07, 63¢; '10, (2¢) net; gains (loss) on discont. ops.: '04, (77¢); '05, 31¢; '06, 1¢; '07, 7¢. '08 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds paid in late Feb., May, Aug. & Nov. ■ Div'd reinvestment plan avail. (C) Incl. def'd chgs. In '10: $2.77/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '09 (elec.): 10.25%-12.25%; in '09 (gas): 9.75%-11.75%; earned on avg. com. eq., '10: 11.4%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	65

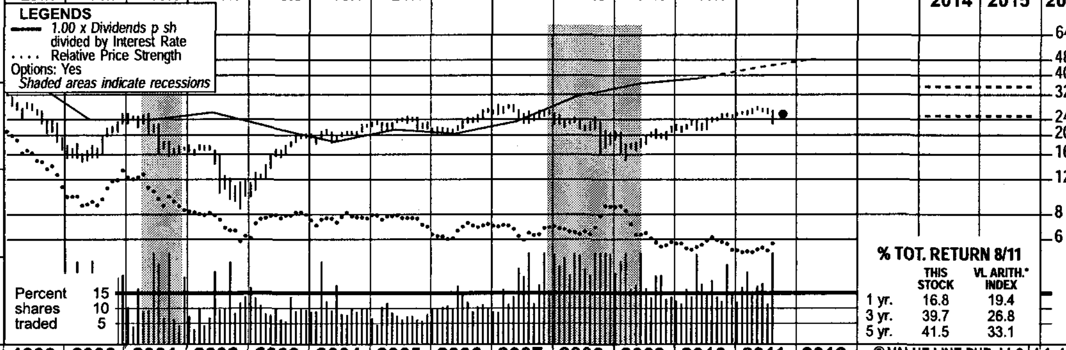
WESTAR ENERGY NYSE-WR

RECENT PRICE 25.54 | P/E RATIO 14.8 (Trailing: 15.0; Median: 14.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 5.1% | VALUE LINE

TIMELINESS 3 Lowered 3/11/11
SAFETY 2 Raised 4/1/05
TECHNICAL 3 Lowered 9/9/11
BETA .75 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	25.9	25.9	18.0	20.5	22.9	25.0	27.2	28.6	25.9	22.3	25.9	28.0
Low:	14.7	15.6	8.5	9.8	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6

LEGENDS
—— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range 2014 | 2015 | 2016

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+35%)	12%
Low	25	(Nil)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	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	3	0	3	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	121	107	98
to Sell	88	98	107
Hld's(000)	81435	81083	77664

Percent shares traded 15 10 5

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.8	19.4
3 yr.	39.7	26.8
5 yr.	41.5	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
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	16.98	17.04	18.34	*18.15*	*18.60*	Revenues per sh	*20.30*
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	3.14	3.59	4.24	*4.05*	*4.30*	"Cash Flow" per sh	*4.90*
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	1.31	1.28	1.80	*1.68*	*1.90*	Earnings per sh A	*2.40*
2.03	2.07	2.10	2.14	2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	*1.28*	*1.32*	Div'd Decl'd per sh B■†	*1.44*
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	8.65	5.26	4.82	*5.75*	*5.85*	Cap'l Spending per sh	*7.05*
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	20.18	20.59	21.25	*21.60*	*22.10*	Book Value per sh C	*23.45*
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	108.31	109.07	112.13	*117.00*	*120.00*	Common Shs Outst'g E	*128.00*
11.7	11.7	--	18.4	17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.78	.73	--	.96	.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.84	*Value Line*		Relative P/E Ratio	*.85*
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%	5.2%	6.3%	5.3%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $3259.0 mill. **Due in 5 Yrs** $857.5 mill.
LT Debt $2761.0 mill. **LT Interest** $165.0 mill.
(LT interest earned: 2.6x)

Pension Assets-12/10 $432 mill. **Oblig.** $747 mill.

Pfd Stock $21.4 mill. **Pfd Div'd** $1.0 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 115,812,605 shs. **as of 7/26/11**
MARKET CAP: $3.0 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
2186.3	1771.1	1461.1	1464.5	1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	*2125*	*2230*	Revenues ($mill)	*2600*
d40.0	72.0	108.1	100.1	134.9	165.3	168.4	136.8	141.3	203.9	*195*	*225*	Net Profit ($mill)	*305*
NMF	53.4%	43.1%	25.0%	31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	5.0%	--	--	--	10.4%	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
61.8%	71.6%	66.2%	53.8%	52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	*52.5%*	*53.0%*	Long-Term Debt Ratio	*54.0%*
37.7%	22.9%	33.2%	45.5%	47.2%	49.3%	48.9%	49.7%	46.1%	46.4%	*47.5%*	*47.0%*	Common Equity Ratio	*46.0%*
4822.4	4272.4	3127.3	3049.2	3000.4	3124.2	3738.3	4400.1	4866.8	5180.8	*5325*	*5650*	Total Capital ($mill)	*6500*
4042.9	3995.4	3909.5	3911.0	3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	*6300*	*6750*	Net Plant ($mill)	*7800*
1.5%	4.4%	7.0%	5.5%	6.2%	6.7%	5.8%	4.2%	4.4%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
NMF	5.9%	10.2%	7.1%	9.4%	10.6%	9.1%	6.2%	6.2%	8.1%	*7.5%*	*8.5%*	Return on Shr. Equity	*10.0%*
NMF	7.3%	10.3%	7.1%	9.5%	10.7%	9.2%	6.2%	6.3%	8.2%	*7.5%*	*8.5%*	Return on Com Equity D	*10.0%*
NMF	NMF	4.9%	3.2%	4.3%	5.5%	4.3%	1.2%	.8%	2.8%	*2.0%*	*2.5%*	Retained to Com Eq	*4.0%*
NMF	120%	53%	56%	55%	49%	53%	80%	87%	65%	*76%*	*70%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.0	-2.0	+6.2
Avg. Indust. Use (MWH)	5769	5145	5468
Avg. Indust. Revs. per KWH (¢)	5.06	5.67	5.82
Capacity at Peak (Mw)	6508	6807	6756
Peak Load, Summer (Mw)	4754	4545	5485
Annual Load Factor (%)	55.0	54.5	55.0
% Change Customers (yr-end)	+.7	+.9	+.3
Fixed Charge Cov. (%)	263	226	267

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-6.0%	-1.0%	*2.5%*
"Cash Flow"	-6.0%	1.5%	*5.0%*
Earnings	--	1.0%	*8.5%*
Dividends	-4.5%	7.0%	*3.0%*
Book Value	-3.0%	6.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	406.8	451.2	574.9	406.1	1839.0
2009	421.8	467.8	528.5	440.1	1858.2
2010	459.8	495.2	644.4	456.8	2056.2
2011	481.7	524.9	*650*	*468.4*	*2125*
2012	*500*	*540*	*680*	*510*	*2230*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.23	.06	.81	.21	1.31
2009	.10	.35	.73	.10	1.28
2010	.27	.47	1.01	.04	1.80
2011	.27	.38	*.96*	*.07*	*1.68*
2012	*.32*	*.48*	*1.00*	*.10*	*1.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.25	.27	.27	.27	1.06
2008	.27	.29	.29	.29	1.14
2009	.29	.30	.30	.30	1.19
2010	.30	.31	.31	.31	1.23
2011	.31	.32	.32		

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 687,000 customers in Kansas. Electric revenue sources: residential and rural, 43%; commercial, 37%; industrial, 20%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2010 depreciation rate: 4.6%. Estimated plant age: 13 years. Fuels: coal, 51%; nuclear, 8%; gas, 41%. Has 2,409 employees. BlackRock, Inc. owns 6.3% of common; off. & dir., less than 1% (4/11 proxy). Chairman: Charles Q. Chandler IV. Chief Executive Officer: Mark A. Ruelle. Inc.: Kansas. Address: 818 South Kansas Avenue, *Topeka, Kansas 66612. Telephone:* 785-575-6300. Internet: www.westarenergy.com.

Shares of Westar Energy have rebounded in recent weeks, following a mid-summer selloff. The company reported mixed results for the second quarter. The top line increased at a moderate clip, thanks to higher retail revenue. However, this was more than offset by greater operating expenses, and share net came in somewhat below the prior-year tally.

Mixed performance ought to continue for the remainder of the year. Revenue comparisons should remain favorable in the coming quarters. The economy in Kansas will likely continue to fare better than the nation's. With the state's attractive business climate, unemployment there should remain below the national average, and most industrial sectors should show further improvement. That said, operating costs will probably continue to weigh on the bottom line. Overall, we project higher revenue, but a bottom-line decline for full-year 2011. Share net should rebound in 2012, assuming solid revenue growth and greater control of operating costs.

We anticipate further investment in operations going forward. Westar continues to make progress with its 345-kilovolt transmission line from Wichita to Oklahoma. This project is trending favorable with respect to schedule and budget, and will likely be completed by mid-2012. The company continues to move forward with the Prairie Wind joint venture, and invest in environmental controls, too.

Westar is requesting higher rates. The company filed in late August with the Kansas Corporation Commission (KCC), seeking to increase base prices by about 5.85%. This would add about $91 million to revenue, on an annual basis. Westar cited higher operating and maintenance expenses, and the increased cost of complying with federal regulatory requirements, as reasons for the request.

This stock is neutrally ranked for Timeliness. We anticipate higher revenues and share earnings for the company by 2014-2016. Moreover, Westar earns good marks for Safety, Price Stability, and Earnings Predictability. From the present quotation, this issue has decent risk-adjusted total return potential. Income-oriented accounts should find this stock's healthy dividend yield attractive.

Michael Napoli, CFA *September 23, 2011*

(A) EPS diluted from 2010 onward. Excl. nonrecur gains (losses): '96, ($0.19); '97, $7.97; '98, ($1.45); '99, ($1.31); '00, $1.07; '01, 27¢, '02, ($12.06); '03, 77¢; '08, 39¢. Totals may not sum due to rounding. Next egs. rep't due late October. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. regulatory assets. In 2010: $7.68/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '09: 10.4%; earned on avg. com. eq., '10: 8.7%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	75

WISCONSIN ENERGY NYSE-WEC

RECENT PRICE	31.02	P/E RATIO	14.2 (Trailing: 14.6 Median: 14.0)	RELATIVE P/E RATIO	1.06	DIV'D YLD	3.6%	VALUE LINE

TIMELINESS 2 Raised 8/6/10

SAFETY 2 Lowered 7/11/97

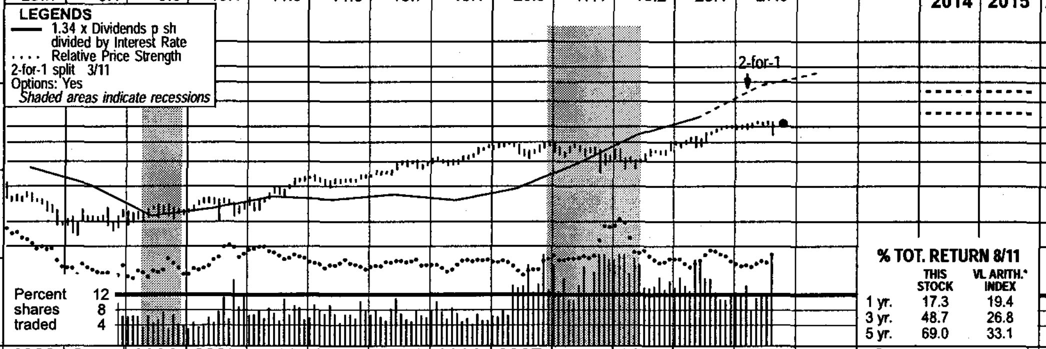
TECHNICAL 3 Lowered 9/16/11

BETA .65 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	11.8	12.3	13.2	16.8	17.3	20.4	24.3	25.2	24.8	25.3	30.5	32.1
Low:	8.4	9.6	10.1	11.3	14.8	16.7	19.1	20.5	17.4	18.2	23.4	27.0

Target Price Range 2014 | 2015 | 2016

LEGENDS
— 1.34 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/11
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	13%
Low	35	(+15%)	7%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	5	2	0	1	3	5	0	8	0
to Sell	3	2	0	1	5	5	0	8	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	175	150	171
to Sell	147	171	155
Hld's(000)	160351	161929	160735

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.3	19.4
3 yr.	48.7	26.8
5 yr.	69.0	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
7.99	7.94	7.93	8.56	9.56	14.14	17.02	16.10	17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	*19.40*	*19.30*	Revenues per sh	*23.50*
2.14	2.13	1.48	2.06	2.26	2.24	2.72	2.84	2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	*3.65*	*3.30*	"Cash Flow" per sh	*5.00*
1.07	.99	.27	.83	.94	.54	.92	1.16	1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	*2.15*	*2.25*	Earnings per sh A	*2.75*
.73	.75	.77	.78	.78	.69	.40	.40	.40	.42	.44	.46	.50	.54	.68	.80	*1.04*	*1.14*	Div'd Decl'd per sh B ■ †	*1.65*
1.25	1.77	1.56	1.76	2.22	2.64	3.01	2.54	2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	*4.35*	*3.10*	Cap'l Spending per sh	*3.00*
8.44	8.71	8.25	8.23	8.44	8.50	8.91	9.22	9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	*17.05*	*17.60*	Book Value per sh C	*19.75*
221.64	223.36	225.73	231.21	237.81	237.29	230.84	232.06	236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	*232.00*	*228.00*	Common Shs Outst'g D	*224.00*
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	14.8	13.3	14.0	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.88	.90	2.73	.94	.76	1.22	.62	.57	.71	.92	.77	.86	.88	.89	.89	.90	*Value Line*		Relative P/E Ratio	*.95*
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%	2.4%	3.2%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $4907.6 mill. **Due in 5 Yrs** $1729.0 mill.
LT Debt $4334.6 mill. **LT Interest** $244.9 mill.
Incl. $132.4 mill. capitalized leases.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $22.8 mill.
Pension Assets-12/10 $1.06 bill.
Oblig. $1.22 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 233,739,777 shs.
MARKET CAP: $7.2 billion (Large Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
3928.5	3736.2	4054.3	3431.1	3815.5	3996.4	4237.8	4431.0	4127.9	4202.5	*4500*	*4400*	Revenues ($mill)	*5250*
218.8	270.8	269.2	221.2	304.8	313.7	337.7	359.8	378.4	455.6	*510*	*520*	Net Profit ($mill)	*625*
40.9%	37.4%	35.5%	37.5%	32.9%	35.8%	39.1%	37.6%	36.5%	35.4%	*34.5%*	*35.0%*	Income Tax Rate	*34.0%*
6.9%	4.1%	6.9%	10.0%	12.5%	19.0%	23.8%	27.2%	25.0%	18.6%	*12.0%*	*10.0%*	AFUDC % to Net Profit	*8.0%*
62.2%	59.8%	59.9%	56.2%	52.8%	51.3%	50.3%	54.8%	51.9%	50.6%	*54.0%*	*54.0%*	Long-Term Debt Ratio	*53.5%*
37.2%	39.6%	39.6%	43.3%	46.7%	48.2%	49.2%	44.8%	47.7%	49.0%	*46.0%*	*45.5%*	Common Equity Ratio	*46.5%*
5523.8	5400.3	5963.3	5762.3	5741.5	5992.8	6302.1	7442.0	7473.1	7764.5	*8640*	*8800*	Total Capital ($mill)	*9475*
4188.0	4398.8	5926.1	5903.1	6362.9	7052.5	7681.2	8517.0	9070.5	9601.5	*10275*	*10750*	Net Plant ($mill)	*11225*
5.8%	7.1%	6.3%	5.6%	7.0%	6.6%	7.0%	6.3%	6.4%	7.5%	*7.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
10.5%	12.5%	11.3%	8.8%	11.2%	10.7%	10.8%	10.7%	10.5%	11.9%	*13.0%*	*13.0%*	Return on Shr. Equity	*14.0%*
10.6%	12.6%	11.4%	8.8%	11.3%	10.8%	10.9%	10.7%	10.6%	12.0%	*13.0%*	*13.0%*	Return on Com Equity E	*14.0%*
6.0%	8.3%	7.4%	4.9%	7.5%	7.1%	7.1%	7.0%	6.2%	7.0%	*6.5%*	*6.5%*	Retained to Com Eq	*6.0%*
43%	35%	35%	45%	34%	35%	35%	35%	42%	41%	*48%*	*50%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.2	-8.1	+6.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.05	6.57	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5740	5812	5908
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.2	+.3
Fixed Charge Cov. (%)	270	281	312

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	5.5%	2.5%	4.5%
"Cash Flow"	3.5%	2.5%	8.0%
Earnings	8.0%	8.5%	8.5%
Dividends	-1.0%	10.0%	16.0%
Book Value	6.0%	7.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1431.8	946.1	852.5	1200.6	4431.0
2009	1396.2	842.5	821.9	1067.3	4127.9
2010	1248.6	890.9	973.2	1089.8	4202.5
2011	1328.7	991.7	*979.6*	*1200*	*4500*
2012	*1325*	*975*	*925*	*1175*	*4400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.52	.25	.33	.42	1.52
2009	.60	.27	.25	.48	1.60
2010	.55	.37	.47	.53	1.92
2011	.72	.41	*.47*	*.55*	*2.15*
2012	*.75*	*.42*	*.50*	*.58*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.125	.125	.125	.125	.50
2008	.135	.135	.135	.135	.54
2009	.169	.169	.169	.169	.68
2010	.20	.20	.20	.20	.80
2011	.26	.26	.26		

BUSINESS: Wisconsin Energy Corporation is a holding company for We Energies, which provides electric, gas & steam service in Wisconsin. Customers: 1.1 mill. elec., 1.1 mill. gas. Acq'd WICOR 4/00. Discontinued pump-manufacturing operations in '04. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 38%; small commercial & industrial, 31%; large commercial & industrial, 23%; other, 8%. Generating sources: coal, 54%; gas, 9%; hydro, 1%; wind, 1%; purchased, 35%. Fuel costs: 44% of revs. '10 reported deprec. rate (utility): 2.8%. Has 4,600 employees. Chairman, President & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

Wisconsin Energy is awaiting a decision from the state commission about the company's regulatory proposal. Typically, the utility would have filed a general rate case in May, with new tariffs taking effect the following January. But, in order to reduce rate pressure on its customers, the company made an alternative proposal. Instead of filing a general rate case, Wisconsin Energy proposed that it be allowed to suspend $140.1 million of regulatory amortization in 2012. This would help lift earnings next year without a base rate hike. The utility would file a general rate case in 2012, with new tariffs taking effect in 2013. However, if the commission rejects this idea, the company would file a general rate case. Wisconsin Energy would request electric, gas, and steam increases of $170.6 million, $6.0 million, and $3.6 million, respectively. The commission's decision is expected next month.

Earnings are likely to rise in 2011 and 2012. This year, Wisconsin Energy is benefiting from the income from a coal-fired facility that began commercial operation in early 2011. Hot weather is another plus, and has helped offset the effect of the sputtering economy on electric demand. The beginning of a $300 million stock buyback program should help, too. We assume the adoption of Wisconsin Energy's aforementioned regulatory proposal in our 2012 profit forecast.

A general rate case is pending in Michigan. The utility is seeking an increase of $14.9 million, based on a 10.4% return on equity. The company expects to self-implement a $7.7 million hike in January. The final order is due in July.

Two renewable-energy projects are being built. The company is spending $361 million to add 162 megawatts of wind capacity. This project should be completed by yearend. A 50-mw biomass plant is expected to be in service by the end of 2013 at a projected cost of $255 million.

This timely stock is suitable for utility investors who are focused on dividend growth. The payout ratio is now low, by utility standards, but the company wants to raise it to 60%. Accordingly, hefty dividend boosts are likely to occur. This should produce an above-average (for a utility) total return through mid-decade.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (5¢); '00, 10¢ net; '02, (44¢); '03, (10¢) net; '04, (42¢); gains on disc. ops.: '04, 77¢; '05, 2¢; '06, 2¢; '09, 2¢; '10, 1¢; '11, 5¢. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '10: $6.55/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates allowed on com. eq. in '10: 10.4%-10.5%; earned on avg. com. eq., '09: 10.8%. Regulatory Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	90

ATTACHMENT B

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AMEREN CORP (NYSE)					ZACKS RANK: 3 - HOLD
AEE	32.74	0.45	(1.39%)	Vol. 1,307,632	15:07 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)

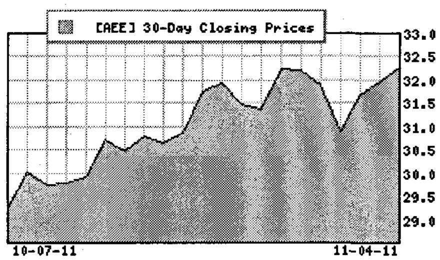
General Information

AMEREN CORP
1901 CHOUTEAU AVE
ST LOUIS, MO 63103
Phone: 314-621-3222
Fax: 314-621-2888
Web: http://www.ameren.com
Email: invest@ameren.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/21/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.29
52 Week High	33.49
52 Week Low	25.55
Beta	0.63
20 Day Moving Average	1,847,078.25
Target Price Consensus	28.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	10.39	4 Week	1.78
12 Week	17.85	12 Week	10.85
YTD	14.54	YTD	14.95

Share Information		Dividend Information	
Shares Outstanding (millions)	241.67	Dividend Yield	4.77%
		Annual Dividend	$1.54
Market Capitalization (millions)	7,803.40	Payout Ratio	0.59
Short Ratio	2.15	Change in Payout Ratio	-0.09
Last Split Date	N/A	Last Dividend Payout / Amount	09/06/2011 / $0.38

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.32	Current (1=Strong Buy, 5=Strong Sell)	3.20
Current Year EPS Consensus Estimate	2.55	30 Days Ago	3.20
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	3.20
Next EPS Report Date	02/21/2012	90 Days Ago	3.22

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.66	vs. Previous Year	12.14%	vs. Previous Year	0.62%
Trailing 12 Months:	12.28	vs. Previous Quarter	166.10%	vs. Previous Quarter:	27.34%
PEG Ratio	3.17				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.96	09/30/11	8.05	09/30/11	2.74

Price/Cash Flow	5.10	06/30/11	7.54	06/30/11	2.54
Price / Sales	1.02	03/31/11	7.86	03/31/11	2.65
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.45	09/30/11	1.05	09/30/11	8.37
06/30/11	1.51	06/30/11	1.13	06/30/11	7.79
03/31/11	1.48	03/31/11	1.17	03/31/11	8.28
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	11.45	09/30/11	11.45	09/30/11	33.73
06/30/11	5.23	06/30/11	5.23	06/30/11	32.94
03/31/11	5.47	03/31/11	5.47	03/31/11	32.76
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	7.52	09/30/11	0.82	09/30/11	45.04
06/30/11	7.47	06/30/11	0.89	06/30/11	47.04
03/31/11	7.32	03/31/11	0.90	03/31/11	47.48

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AMERICAN ELEC PWR INC (NYSE) **ZACKS RANK: 3 - HOLD**

AEP 39.74 ▲0.04 (0.10%) Vol. 2,300,064 15:30 ET

American Electric Power is a public utility holding company which owns,directly or indirectly, all of the outstanding common stock of its domesticelectric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. The Company's operations are divided into three business segments: Wholesale, Energy Delivery and Other.

General Information

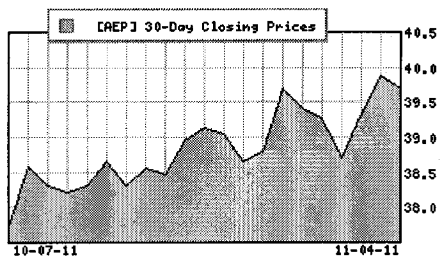
AMER ELEC PWR
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215
Phone: 614-716-1000
Fax: 614-223-1823
Web: http://www.aep.com
Email: klkozero@aep.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	01/27/2012

Price and Volume Information

Zacks Rank	3
Yesterday's Close	39.70
52 Week High	40.08
52 Week Low	33.09
Beta	0.51
20 Day Moving Average	3,840,518.00
Target Price Consensus	40.93



% Price Change		% Price Change Relative to S&P 500	
4 Week	5.19	4 Week	-3.01
12 Week	11.02	12 Week	4.43
YTD	10.34	YTD	10.73

Share Information		Dividend Information	
Shares Outstanding (millions)	482.27	Dividend Yield	4.63%
		Annual Dividend	$1.84
Market Capitalization (millions)	19,146.28	Payout Ratio	0.59
Short Ratio	1.53	Change in Payout Ratio	0.04
Last Split Date	N/A	Last Dividend Payout / Amount	08/08/2011 / $0.46

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.41	Current (1=Strong Buy, 5=Strong Sell)	2.31
Current Year EPS Consensus Estimate	3.12	30 Days Ago	2.31
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.19
Next EPS Report Date	01/27/2012	90 Days Ago	2.24

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.73	vs. Previous Year	1.74%	vs. Previous Year	4.88%
Trailing 12 Months:	12.81	vs. Previous Quarter	60.27%	vs. Previous Quarter:	19.44%
PEG Ratio	3.18				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.31	09/30/11	10.64	09/30/11	2.93

Price/Cash Flow	5.94	06/30/11	10.73	06/30/11	2.93
Price / Sales	1.28	03/31/11	10.88	03/31/11	2.94
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.77	09/30/11	0.56	09/30/11	9.93
06/30/11	0.81	06/30/11	0.59	06/30/11	9.97
03/31/11	0.80	03/31/11	0.58	03/31/11	10.15
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	16.13	09/30/11	16.13	09/30/11	30.38
06/30/11	15.18	06/30/11	15.18	06/30/11	28.93
03/31/11	13.23	03/31/11	13.23	03/31/11	28.64
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	7.31	09/30/11	1.04	09/30/11	50.89
06/30/11	6.78	06/30/11	1.12	06/30/11	52.85
03/31/11	6.52	03/31/11	1.13	03/31/11	53.24

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CENTERPOINT ENERGY INC (NYSE) **ZACKS RANK: 3 - HOLD**

CNP 20.36 ▲0.05 (0.25%) Vol. 1,945,008 15:12 ET

CenterPoint Energy is a domestic energy delivery company that includes electricity transmission and distribution, natural gas distribution and sales, interstate pipeline and gathering operations. They serve customers in Arkansas, Illinois, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.

General Information

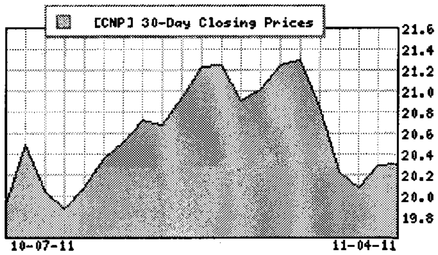
CENTERPOINT EGY
1111 LOUISIANA ST.
HOUSTON, TX 77002
Phone: 7132073000
Fax: 713-207-3169
Web: http://www.centerpointenergy.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	03/06/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.31
52 Week High	21.47
52 Week Low	15.09
Beta	0.65
20 Day Moving Average	5,139,217.00
Target Price Consensus	21.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.91	4 Week	-6.04
12 Week	8.61	12 Week	2.16
YTD	29.20	YTD	29.65

Share Information		Dividend Information	
Shares Outstanding (millions)	425.86	Dividend Yield	3.89%
		Annual Dividend	$0.79
Market Capitalization (millions)	8,649.14	Payout Ratio	0.64
Short Ratio	1.28	Change in Payout Ratio	-0.02
Last Split Date	12/11/1995	Last Dividend Payout / Amount	08/12/2011 / $0.20

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.20	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	1.13	30 Days Ago	1.85
Estimated Long-Term EPS Growth Rate	5.70	60 Days Ago	1.85
Next EPS Report Date	03/06/2012	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	18.02	vs. Previous Year	27.59%	vs. Previous Year	-1.42%
Trailing 12 Months:	16.38	vs. Previous Quarter	54.17%	vs. Previous Quarter:	2.40%
PEG Ratio	3.18				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.06	09/30/11	15.10	09/30/11	2.64

Price/Cash Flow	6.39	06/30/11	15.31	06/30/11	2.52
Price / Sales	1.03	03/31/11	14.82	03/31/11	2.40
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.85	09/30/11	0.67	09/30/11	6.28
06/30/11	0.86	06/30/11	0.73	06/30/11	5.86
03/31/11	0.92	03/31/11	0.83	03/31/11	5.62
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	14.03	09/30/11	14.03	09/30/11	9.88
06/30/11	9.35	06/30/11	9.35	06/30/11	7.79
03/31/11	8.67	03/31/11	8.67	03/31/11	7.68
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	17.98	09/30/11	2.02	09/30/11	66.88
06/30/11	18.39	06/30/11	2.57	06/30/11	71.98
03/31/11	18.37	03/31/11	2.67	03/31/11	72.78

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CLECO CORP NEW (NYSE)					**ZACKS RANK: 1 - STRONG BUY**
CNL	36.80	↑0.14	(0.38%)	Vol. 392,184	15:12 ET

Cleco Corp. is an energy services company based in central Louisiana. Their two primary businesses are Cleco Power LLC, a regulated electric utility business, and Cleco Midstream Resources LLC, a wholesale energy business. They use a mixture of western coal, petroleum coke (petcoke), lignite, oil, and natural gas to serve their customers. This diverse fuel mix helps Cleco deliver reliable, low-cost power to its customers.

General Information

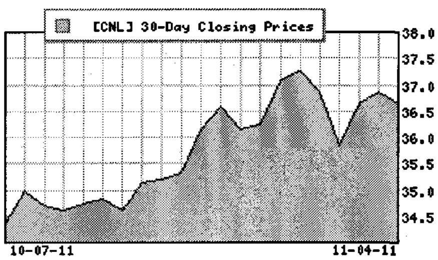
CLECO CORP
2030 DONAHUE FERRY ROAD
PINEVILLE, LA 71361-5000
Phone: 3184847400
Fax: 318-484-7465
Web: http://www.cleco.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/23/2012

Price and Volume Information

Zacks Rank	1
Yesterday's Close	36.66
52 Week High	37.74
52 Week Low	30.05
Beta	0.50
20 Day Moving Average	568,663.88
Target Price Consensus	37.83



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	6.69	4 Week	-1.63
12 Week	9.76	12 Week	3.24
YTD	19.18	YTD	19.60

Share Information		**Dividend Information**	
Shares Outstanding (millions)	61.06	Dividend Yield	3.41%
		Annual Dividend	$1.25
Market Capitalization (millions)	2,238.53	Payout Ratio	0.46
Short Ratio	4.37	Change in Payout Ratio	-0.10
Last Split Date	05/22/2001	Last Dividend Payout / Amount	11/03/2011 / $0.31

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.39	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	2.37	30 Days Ago	2.25
Estimated Long-Term EPS Growth Rate	7.00	60 Days Ago	2.25
Next EPS Report Date	02/23/2012	90 Days Ago	2.40

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	15.45	vs. Previous Year	31.33%	vs. Previous Year	2.24%
Trailing 12 Months:	15.15	vs. Previous Quarter	109.62%	vs. Previous Quarter:	28.82%
PEG Ratio	2.21				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.59	09/30/11	10.86	09/30/11	3.62

Price/Cash Flow	7.24	06/30/11	9.84	06/30/11	3.24
Price / Sales	1.97	03/31/11	10.19	03/31/11	3.31
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.51	09/30/11	1.25	09/30/11	12.99
06/30/11	1.49	06/30/11	1.24	06/30/11	11.64
03/31/11	1.00	03/31/11	0.78	03/31/11	11.77
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	24.11	09/30/11	24.11	09/30/11	23.03
06/30/11	23.32	06/30/11	23.32	06/30/11	22.75
03/31/11	18.46	03/31/11	18.46	03/31/11	21.86
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	5.11	09/30/11	0.97	09/30/11	49.36
06/30/11	4.74	06/30/11	1.00	06/30/11	50.01
03/31/11	4.44	03/31/11	1.03	03/31/11	50.81

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CMS ENERGY CORP (NYSE)

ZACKS RANK: 3 - HOLD

CMS 20.71 ▲0.12 (0.58%) Vol. 1,346,071 15:14 ET

CMS Energy Corporation is a diversified energy company operating in the United States and around the world. The company's two principal subsidiaries are Consumers Energy Company and CMS Enterprises Company. Consumers Energy Company is a public utility that provides natural gas or electricity to residents in Michigan's lower peninsula. CMS Enterprises Company, through subsidiaries, is engaged in several domestic and international diversified energy businesses.

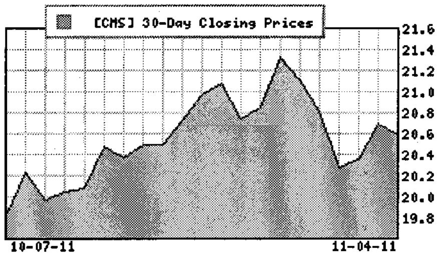
General Information

CMS ENERGY
ONE ENERGY PLAZA
JACKSON, MI 49201
Phone: 5177881612
Fax: 517-788-1859
Web: http://www.cmsenergy.com
Email: invstrel@cmsenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/23/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.59
52 Week High	21.58
52 Week Low	16.96
Beta	0.53
20 Day Moving Average	3,475,116.50
Target Price Consensus	22.73



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.88	4 Week	-4.22
12 Week	12.88	12 Week	6.18
YTD	10.70	YTD	11.09

Share Information		Dividend Information	
Shares Outstanding (millions)	253.36	Dividend Yield	4.08%
		Annual Dividend	$0.84
Market Capitalization (millions)	5,216.60	Payout Ratio	0.56
Short Ratio	3.25	Change in Payout Ratio	0.19
Last Split Date	N/A	Last Dividend Payout / Amount	11/02/2011 / $0.21

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.37	Current (1=Strong Buy, 5=Strong Sell)	1.92
Current Year EPS Consensus Estimate	1.45	30 Days Ago	1.77
Estimated Long-Term EPS Growth Rate	5.50	60 Days Ago	1.77
Next EPS Report Date	02/23/2012	90 Days Ago	1.77

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.23	vs. Previous Year	1.92%	vs. Previous Year	1.46%
Trailing 12 Months:	13.64	vs. Previous Quarter	103.85%	vs. Previous Quarter:	7.33%
PEG Ratio	2.59				

Price Ratios		ROE		ROA	

Price/Book	1.69	09/30/11	13.32	09/30/11	2.50
Price/Cash Flow	5.15	06/30/11	13.72	06/30/11	2.54
Price / Sales	0.79	03/31/11	13.91	03/31/11	2.56
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.29	09/30/11	0.71	09/30/11	6.02
06/30/11	1.32	06/30/11	0.89	06/30/11	6.10
03/31/11	1.20	03/31/11	0.89	03/31/11	6.07
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	8.99	09/30/11	8.99	09/30/11	12.18
06/30/11	9.20	06/30/11	9.20	06/30/11	11.89
03/31/11	9.97	03/31/11	9.97	03/31/11	11.62
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	4.67	09/30/11	2.01	09/30/11	66.79
06/30/11	4.50	06/30/11	2.12	06/30/11	67.94
03/31/11	4.36	03/31/11	2.08	03/31/11	67.57

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CONSTELLATION ENERGY GROUP I (NYSE) **ZACKS RANK: 3 - HOLD**

CEG 39.99 ▲0.78 (1.99%) Vol. 1,318,856 15:14 ET

Baltimore Gas and Electric Company consists primarily of generating, purchasing, and selling electricity and purchasing, transporting, and selling natural gas.

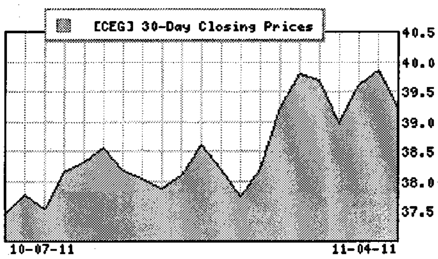
General Information

CONSTELLATN EGY
100 CONSTELLATION WAY
BALTIMORE, MD 21202
Phone: 4104702800
Fax: 410-234-5220
Web: http://www.constellation.com
Email: InvestorRelations@constellation.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/10/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	39.21
52 Week High	40.22
52 Week Low	27.64
Beta	0.97
20 Day Moving Average	2,614,567.25
Target Price Consensus	40.6



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.70	4 Week	-3.47
12 Week	9.99	12 Week	3.45
YTD	28.01	YTD	28.46

Share Information		Dividend Information	
Shares Outstanding (millions)	201.32	Dividend Yield	2.45%
		Annual Dividend	$0.96
Market Capitalization (millions)	7,893.83	Payout Ratio	0.39
Short Ratio	1.36	Change in Payout Ratio	0.02
Last Split Date	05/18/1992	Last Dividend Payout / Amount	09/08/2011 / $0.24

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.64	Current (1=Strong Buy, 5=Strong Sell)	2.75
Current Year EPS Consensus Estimate	2.98	30 Days Ago	2.75
Estimated Long-Term EPS Growth Rate	4.80	60 Days Ago	2.75
Next EPS Report Date	02/10/2012	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.14	vs. Previous Year	41.67%	vs. Previous Year	-11.28%
Trailing 12 Months:	15.75	vs. Previous Quarter	-10.53%	vs. Previous Quarter:	4.80%
PEG Ratio	2.76				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.98	09/30/11	6.44	09/30/11	2.61
Price/Cash Flow	5.27	06/30/11	6.02	06/30/11	2.44

Price / Sales	0.57	03/31/11	5.76	03/31/11	2.34
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.57	09/30/11	1.39	09/30/11	3.72
06/30/11	1.64	06/30/11	1.45	06/30/11	3.32
03/31/11	1.80	03/31/11	1.62	03/31/11	3.29
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	5.57	09/30/11	5.57	09/30/11	40.19
06/30/11	-11.79	06/30/11	-11.79	06/30/11	40.43
03/31/11	-12.25	03/31/11	-12.25	03/31/11	40.29
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	20.35	09/30/11	0.56	09/30/11	35.48
06/30/11	22.89	06/30/11	0.53	06/30/11	34.21
03/31/11	24.03	03/31/11	0.55	03/31/11	35.02

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DTE ENERGY CO (NYSE)

ZACKS RANK: 3 - HOLD

DTE 52.07 ▼-0.05 (-0.10%) Vol. 661,000 15:15 ET

DTE Energy is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Its largest operating units are Detroit Edison, an electric utility serving 2.1 million customers in Southeastern Michigan, and MichCon, a natural gas utility serving 1.2 million customers in Michigan. Detroit Edison is the Company's principal operating subsidiary. Affiliates of the Company are engaged in non-regulated businesses, including energy-related services and products.

General Information

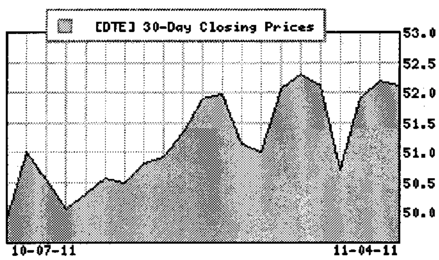
DTE ENERGY CO
ONE ENERGY PLAZA
DETROIT, MI 48226
Phone: 3132354000
Fax: -
Web: eMail: sholdersvcs@dteenergy.com
Email: www.bnymellon.com/shareowner/isd

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/08/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	52.12
52 Week High	52.82
52 Week Low	43.22
Beta	0.65
20 Day Moving Average	1,151,856.63
Target Price Consensus	51.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.43	4 Week	-3.72
12 Week	11.01	12 Week	4.42
YTD	15.00	YTD	15.41

Share Information		Dividend Information	
Shares Outstanding (millions)	169.33	Dividend Yield	4.51%
		Annual Dividend	$2.35
Market Capitalization (millions)	8,825.43	Payout Ratio	0.63
Short Ratio	1.57	Change in Payout Ratio	-0.01
Last Split Date	N/A	Last Dividend Payout / Amount	09/15/2011 / $0.59

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.87	Current (1=Strong Buy, 5=Strong Sell)	2.90
Current Year EPS Consensus Estimate	3.60	30 Days Ago	2.67
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.67
Next EPS Report Date	02/08/2012	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.46	vs. Previous Year	11.46%	vs. Previous Year	5.89%
Trailing 12 Months:	14.05	vs. Previous Quarter	64.62%	vs. Previous Quarter:	11.69%
PEG Ratio	2.89				

Price Ratios	ROE	ROA

Price/Book	1.26	09/30/11	9.20	09/30/11	2.56
Price/Cash Flow	5.39	06/30/11	9.02	06/30/11	2.49
Price / Sales	0.99	03/31/11	8.43	03/31/11	2.32
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.39	09/30/11	1.02	09/30/11	7.09
06/30/11	1.23	06/30/11	0.93	06/30/11	6.97
03/31/11	1.10	03/31/11	0.89	03/31/11	6.64
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	10.77	09/30/11	10.77	09/30/11	41.39
06/30/11	10.60	06/30/11	10.60	06/30/11	40.30
03/31/11	10.37	03/31/11	10.37	03/31/11	40.37
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.27	09/30/11	1.07	09/30/11	51.68
06/30/11	9.23	06/30/11	1.10	06/30/11	52.38
03/31/11	9.34	03/31/11	1.03	03/31/11	50.64

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EDISON INTL (NYSE)

ZACKS RANK: 3 - HOLD

EIX 41.03 ▲0.27 (0.66%) Vol. 1,282,702 15:16 ET

Edison International is an international electric power generator, distributor and structured finance provider. Edison International is one of the industry leaders in privatized, deregulated and incentive-regulated markets and power generation. It is the parent company of Edison Mission Energy, Southern California Edison, Edison Capita, Edison Enterprises and Edison O&M Services. (Company Press Release)

General Information

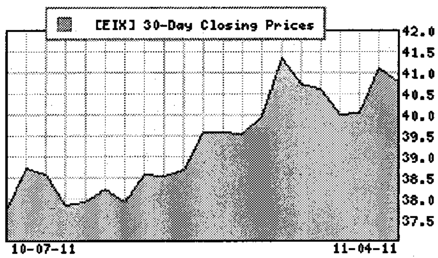
EDISON INTL
2244 WALNUT GROVE AVE STE 369 P O BOX
800
ROSEMEAD, CA 91770
Phone: (626) 302-2222
Fax: 626-302-2117
Web: http://www.edison.com
Email: invrel@sce.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	03/05/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.76
52 Week High	41.57
52 Week Low	32.64
Beta	0.66
20 Day Moving Average	2,342,882.75
Target Price Consensus	42.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	8.00	4 Week	-0.42
12 Week	17.19	12 Week	10.23
YTD	5.60	YTD	5.97

Share Information		Dividend Information	
Shares Outstanding (millions)	325.81	Dividend Yield	3.14%
		Annual Dividend	$1.28
Market Capitalization (millions)	13,280.06	Payout Ratio	0.42
Short Ratio	1.47	Change in Payout Ratio	0.06
Last Split Date	06/22/1993	Last Dividend Payout / Amount	09/28/2011 / $0.32

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.45	Current (1=Strong Buy, 5=Strong Sell)	1.71
Current Year EPS Consensus Estimate	2.93	30 Days Ago	1.71
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	1.86
Next EPS Report Date	03/05/2012	90 Days Ago	2.13

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.90	vs. Previous Year	-10.27%	vs. Previous Year	-10.61%
Trailing 12 Months:	13.36	vs. Previous Quarter	142.59%	vs. Previous Quarter:	13.51%
PEG Ratio	2.78				

Price Ratios	ROE	ROA

Price/Book	1.21	09/30/11	9.35	09/30/11	2.16
Price/Cash Flow	4.78	06/30/11	9.95	06/30/11	2.30
Price / Sales	1.09	03/31/11	10.19	03/31/11	2.38
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.14	09/30/11	1.00	09/30/11	8.22
06/30/11	1.12	06/30/11	0.97	06/30/11	8.41
03/31/11	1.17	03/31/11	1.02	03/31/11	8.66
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	12.18	09/30/11	12.18	09/30/11	33.81
06/30/11	12.51	06/30/11	12.51	06/30/11	32.93
03/31/11	12.48	03/31/11	12.48	03/31/11	32.78
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	15.48	09/30/11	1.18	09/30/11	51.92
06/30/11	15.45	06/30/11	1.21	06/30/11	52.43
03/31/11	15.40	03/31/11	1.17	03/31/11	51.68

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GREAT PLAINS ENERGY INC (NYSE)

ZACKS RANK: 3 - HOLD

GXP 21.24 ▲0.10 (0.47%) Vol. 881,157 15:17 ET

Great Plains Energy Incorporated engages in the generation, transmission, distribution and sale of electricity to customers located in all or portions of numerous counties in western Missouri and eastern Kansas. Customers include residences, commercial firms, and industrials, municipalities and other electric utilities.

General Information

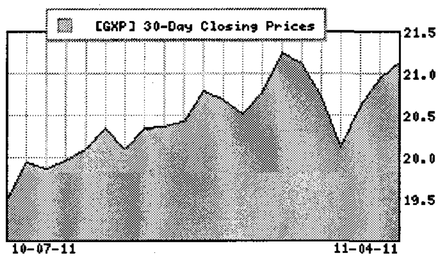
GREAT PLAINS EN
1200 MAIN ST.
KANSAS CITY, MO 64106-2124
Phone: 8165562200
Fax: 816-556-2446
Web: http://www.greatplainsenergy.com
Email: eula.jones@kcpl.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/23/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	21.14
52 Week High	21.33
52 Week Low	16.34
Beta	0.71
20 Day Moving Average	1,138,111.63
Target Price Consensus	21



% Price Change		% Price Change Relative to S&P 500	
4 Week	8.52	4 Week	0.06
12 Week	18.03	12 Week	11.02
YTD	9.03	YTD	9.41

Share Information		Dividend Information	
Shares Outstanding (millions)	135.95	Dividend Yield	3.93%
		Annual Dividend	$0.83
Market Capitalization (millions)	2,873.94	Payout Ratio	0.70
Short Ratio	4.44	Change in Payout Ratio	-0.10
Last Split Date	06/01/1992	Last Dividend Payout / Amount	08/25/2011 / $0.21

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.02	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	1.26	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	1.86
Next EPS Report Date	02/23/2012	90 Days Ago	1.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.78	vs. Previous Year	-5.21%	vs. Previous Year	6.16%
Trailing 12 Months:	17.76	vs. Previous Quarter	193.55%	vs. Previous Quarter:	36.91%
PEG Ratio	2.58				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.96	09/30/11	5.76	09/30/11	1.88

Price/Cash Flow	5.09	06/30/11	5.99	06/30/11	1.96
Price / Sales	1.25	03/31/11	6.75	03/31/11	2.21
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.44	09/30/11	0.30	09/30/11	7.28
06/30/11	0.42	06/30/11	0.28	06/30/11	7.67
03/31/11	0.39	03/31/11	0.23	03/31/11	8.65
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	10.66	09/30/11	10.66	09/30/11	21.95
06/30/11	10.89	06/30/11	10.89	06/30/11	21.19
03/31/11	12.47	03/31/11	12.47	03/31/11	21.12
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	3.19	09/30/11	0.92	09/30/11	47.64
06/30/11	3.10	06/30/11	0.99	06/30/11	49.49
03/31/11	2.91	03/31/11	0.98	03/31/11	49.15

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HAWAIIAN ELEC INDUSTRIES (NYSE)					**ZACKS RANK: 4 - SELL**
HE	25.84	-0.84	(-3.15%)	Vol. 614,907	15:17 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.

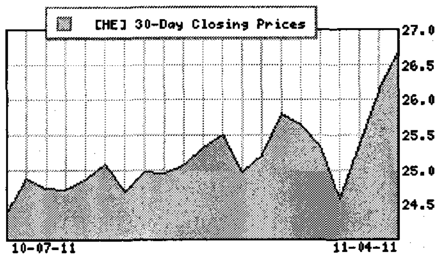
General Information

HAWAIIAN ELEC
900 RICHARDS ST
HONOLULU, HI 96813
Phone: 8085435662
Fax: 808-543-7966
Web: http://www.hei.com
Email: skimura@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/09/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	26.68
52 Week High	26.79
52 Week Low	20.59
Beta	0.51
20 Day Moving Average	465,346.41
Target Price Consensus	24.9



% Price Change		% Price Change Relative to S&P 500	
4 Week	9.34	4 Week	0.81
12 Week	18.95	12 Week	11.88
YTD	17.07	YTD	17.48

Share Information		Dividend Information	
Shares Outstanding (millions)	95.88	Dividend Yield	4.65%
		Annual Dividend	$1.24
Market Capitalization (millions)	2,558.02	Payout Ratio	0.93
Short Ratio	5.75	Change in Payout Ratio	-0.09
Last Split Date	06/14/2004	Last Dividend Payout / Amount	08/11/2011 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.38	Current (1=Strong Buy, 5=Strong Sell)	2.80
Current Year EPS Consensus Estimate	1.40	30 Days Ago	2.80
Estimated Long-Term EPS Growth Rate	8.60	60 Days Ago	2.80
Next EPS Report Date	02/09/2012	90 Days Ago	2.80

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.03	vs. Previous Year	42.86%	vs. Previous Year	27.62%
Trailing 12 Months:	19.91	vs. Previous Quarter	78.57%	vs. Previous Quarter:	11.59%
PEG Ratio	2.22				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.66	09/30/11	8.66	09/30/11	1.42

Price/Cash Flow	9.15	06/30/11	7.68	06/30/11	1.26
Price / Sales	0.83	03/31/11	7.88	03/31/11	1.30
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.94	09/30/11	0.94	09/30/11	4.23
06/30/11	0.93	06/30/11	0.93	06/30/11	3.96
03/31/11	0.93	03/31/11	0.93	03/31/11	4.24
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	6.62	09/30/11	6.62	09/30/11	16.04
06/30/11	6.25	06/30/11	6.25	06/30/11	15.87
03/31/11	6.72	03/31/11	6.72	03/31/11	15.77
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	-	09/30/11	0.87	09/30/11	47.19
06/30/11	-	06/30/11	0.95	06/30/11	49.37
03/31/11	-	03/31/11	0.96	03/31/11	49.63

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IDACORP INC (NYSE) ZACKS RANK: 2 - BUY

IDA 40.43 N/A (N/A%) Vol. 106,455 15:18 ET

Idacorp Inc. is an electric public utility company. The company is engaged in the generation, purchase, transmission, distribution and sale of electric energy primarily in the areas including southern Idaho, eastern Oregon and northern Nevada. The company relies heavily on hydroelectric power for its generating needs and is one of the nation's few investor-owned utilities with a predominantly hydro base. The company's principal commercial and industrial customers include lodges, condominiums, and ski lifts and related facilities.

General Information

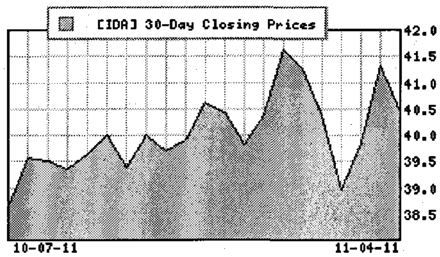
IDACORP INC
1221 WEST IDAHO STREET
BOISE, ID 83702-5627
Phone: 2083882200
Fax: 208-388-6916
Web: www.idacorpinc.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/22/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.43
52 Week High	41.97
52 Week Low	33.88
Beta	0.44
20 Day Moving Average	300,403.66
Target Price Consensus	41



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.61	4 Week	-3.56
12 Week	11.81	12 Week	5.17
YTD	9.33	YTD	9.71

Share Information		Dividend Information	
Shares Outstanding (millions)	49.71	Dividend Yield	2.97%
		Annual Dividend	$1.20
Market Capitalization (millions)	2,009.86	Payout Ratio	0.49
Short Ratio	4.27	Change in Payout Ratio	-0.03
Last Split Date	N/A	Last Dividend Payout / Amount	11/03/2011 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.46	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	3.40	30 Days Ago	2.17
Estimated Long-Term EPS Growth Rate	4.70	60 Days Ago	2.33
Next EPS Report Date	02/22/2012	90 Days Ago	2.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.89	vs. Previous Year	-27.34%	vs. Previous Year	0.09%
Trailing 12 Months:	16.57	vs. Previous Quarter	140.48%	vs. Previous Quarter:	31.77%
PEG Ratio	2.55				

Price Ratios	ROE	ROA

Price/Book	1.21	09/30/11	7.67	09/30/11	2.59
Price/Cash Flow	7.50	06/30/11	8.95	06/30/11	2.99
Price / Sales	1.95	03/31/11	10.35	03/31/11	3.45
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.22	09/30/11	0.84	09/30/11	11.79
06/30/11	0.96	06/30/11	0.68	06/30/11	13.44
03/31/11	1.02	03/31/11	0.78	03/31/11	15.13
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	13.47	09/30/11	13.47	09/30/11	33.41
06/30/11	14.95	06/30/11	14.95	06/30/11	31.61
03/31/11	15.36	03/31/11	15.36	03/31/11	31.43
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	7.46	09/30/11	0.90	09/30/11	47.25
06/30/11	7.74	06/30/11	0.95	06/30/11	48.70
03/31/11	8.23	03/31/11	0.96	03/31/11	48.91

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INTEGRYS ENERGY GROUP INC (NYSE)

ZACKS RANK: 2 - BUY

TEG 52.65 ▼-0.29 (-0.55%) Vol. 549,680 15:18 ET

Integrys Energy Group is a diversified holding company with regulated utility operations operating through six wholly owned subsidiaries. These include the Wisconsin Public Service Corporation, The Peoples Gas Light and Coke Company, North Shore Gas Company, Upper Peninsula Power Company, Michigan Gas Utilities Corporation, and Minnesota Energy Resources Corporation; nonregulated operations serving the competitive energy markets through its wholly owned nonregulated subsidiary, Integrys Energy Services; and also a 34% equity ownership interest in American Transmission Company LLC (an electric transmission company operating in Wisconsin, Michigan, Minnesota, and Illinois).

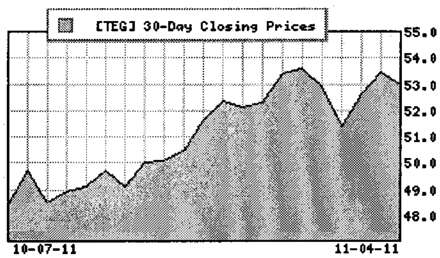
General Information

INTEGRYS ENERGY
130 EAST RANDOLPH DRIVE
CHICAGO, IL 60601
Phone: 800-699-1269
Fax: -
Web: www.integrysgroup.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/22/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	52.94
52 Week High	54.02
52 Week Low	42.76
Beta	0.85
20 Day Moving Average	585,687.00
Target Price Consensus	51.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	9.34	4 Week	0.81
12 Week	12.71	12 Week	6.02
YTD	9.13	YTD	9.52

Share Information		Dividend Information	
Shares Outstanding (millions)	78.29	Dividend Yield	5.14%
		Annual Dividend	$2.72
Market Capitalization (millions)	4,144.57	Payout Ratio	0.85
Short Ratio	5.87	Change in Payout Ratio	-0.06
Last Split Date	N/A	Last Dividend Payout / Amount	08/29/2011 / $0.68

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.05	Current (1=Strong Buy, 5=Strong Sell)	2.57
Current Year EPS Consensus Estimate	3.37	30 Days Ago	2.57
Estimated Long-Term EPS Growth Rate	4.50	60 Days Ago	2.71
Next EPS Report Date	02/22/2012	90 Days Ago	2.71

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.73	vs. Previous Year	22.86%	vs. Previous Year	-5.93%
Trailing 12 Months:	16.54	vs. Previous Quarter	13.16%	vs. Previous Quarter:	-7.13%
PEG Ratio	3.50				

Price Ratios		**ROE**		**ROA**	
Price/Book	1.40	09/30/11	8.55	09/30/11	2.65
Price/Cash Flow	8.06	06/30/11	8.39	06/30/11	2.57
Price / Sales	0.85	03/31/11	8.62	03/31/11	2.63
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.32	09/30/11	1.06	09/30/11	5.21
06/30/11	1.41	06/30/11	1.28	06/30/11	5.01
03/31/11	1.36	03/31/11	1.29	03/31/11	5.11
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	8.83	09/30/11	8.83	09/30/11	37.90
06/30/11	8.11	06/30/11	8.11	06/30/11	38.09
03/31/11	9.47	03/31/11	9.47	03/31/11	38.47
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	19.87	09/30/11	0.70	09/30/11	40.81
06/30/11	19.71	06/30/11	0.71	06/30/11	41.27
03/31/11	19.57	03/31/11	0.72	03/31/11	41.46

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ITC HLDGS CORP (NYSE)

ZACKS RANK: 3 - HOLD

ITC 74.85 -0.33 (-0.44%) Vol. 135,111 15:19 ET

ITC Holdings Corp. is in the business of electricity transmission infrastructure improvements as a means to improve electric reliability, reduce congestion and lower the overall cost of delivered energy. Through ITC operating subsidiaries, ITCTransmission and METC, we are the only publicly traded company engaged exclusively in the transmission of electricity in the United States. We are also the largest independent electric transmission company and the eighth largest electric transmission company in the country based on transmission load served. Its business strategy is to operate, maintain and invest in our transmission infrastructure in order to enhance system integrity and reliability and to reduce transmission constraints. By pursuing this strategy, we seek to reduce the overall cost of delivered energy for end-use consumers by providing them with access to electricity from the lowest cost electricity generation sources.

General Information

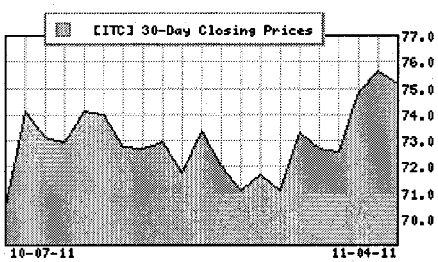
ITC HOLDINGS CP
27175 ENERGY WAY
NOVI, MI 48377
Phone: 248-946-3000
Fax: -
Web: http://www.itc-holdings.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/21/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	75.18
52 Week High	78.89
52 Week Low	59.77
Beta	0.64
20 Day Moving Average	473,241.66
Target Price Consensus	80.83



% Price Change		% Price Change Relative to S&P 500	
4 Week	6.71	4 Week	-1.61
12 Week	6.25	12 Week	-0.06
YTD	21.30	YTD	21.72

Share Information		Dividend Information	
Shares Outstanding (millions)	51.30	Dividend Yield	1.88%
		Annual Dividend	$1.41
Market Capitalization (millions)	3,856.43	Payout Ratio	0.44
Short Ratio	6.93	Change in Payout Ratio	-0.16
Last Split Date	N/A	Last Dividend Payout / Amount	08/30/2011 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.84	Current (1=Strong Buy, 5=Strong Sell)	1.75
Current Year EPS Consensus Estimate	3.33	30 Days Ago	1.50
Estimated Long-Term EPS Growth Rate	16.50	60 Days Ago	1.29
Next EPS Report Date	02/21/2012	90 Days Ago	1.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	22.60	vs. Previous Year	13.33%	vs. Previous Year	7.46%

Trailing 12 Months:	23.49	vs. Previous Quarter	2.41%	vs. Previous Quarter:	3.35%
PEG Ratio	1.37				
Price Ratios		**ROE**		**ROA**	
Price/Book	3.20	09/30/11	14.21	09/30/11	3.71
Price/Cash Flow	16.37	06/30/11	14.08	06/30/11	3.67
Price / Sales	5.18	03/31/11	13.90	03/31/11	3.59
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.99	09/30/11	0.80	09/30/11	22.26
06/30/11	1.02	06/30/11	0.85	06/30/11	21.89
03/31/11	1.17	03/31/11	0.94	03/31/11	21.47
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	34.37	09/30/11	34.37	09/30/11	23.51
06/30/11	34.22	06/30/11	34.22	06/30/11	23.32
03/31/11	33.71	03/31/11	33.71	03/31/11	22.75
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	3.26	09/30/11	2.14	09/30/11	68.12
06/30/11	3.13	06/30/11	2.16	06/30/11	68.31
03/31/11	3.13	03/31/11	2.18	03/31/11	68.52

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PEPCO HOLDINGS INC (NYSE)						**ZACKS RANK: 3 - HOLD**
POM	19.51	-0.07	(-0.36%)	Vol. 868,037	15:20 ET	

Pepco Holdings, Inc. is an energy holding company. Pepco has been providing reliable electric service for more than one hundred years. Today, they deliver electricity to homes and businesses in the District of Columbia and its Maryland suburbs.

General Information

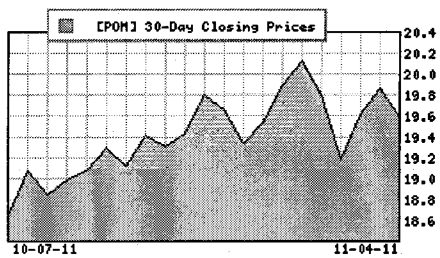
PEPCO HLDGS
SUITE 1300 701 NINTH STREET NW
WASHINGTON, DC 20068
Phone: 202-872-2000
Fax: 202-331-6750
Web: http://www.pepcoholdings.com
Email: investor@pepcoholdings.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/24/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	19.58
52 Week High	20.36
52 Week Low	16.57
Beta	0.52
20 Day Moving Average	1,743,203.63
Target Price Consensus	19.5



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	4.99	4 Week	-3.20
12 Week	7.88	12 Week	1.47
YTD	7.29	YTD	7.67

Share Information		**Dividend Information**	
Shares Outstanding (millions)	226.40	Dividend Yield	5.52%
		Annual Dividend	$1.08
Market Capitalization (millions)	4,432.83	Payout Ratio	0.84
Short Ratio	4.47	Change in Payout Ratio	0.03
Last Split Date	N/A	Last Dividend Payout / Amount	09/08/2011 / $0.27

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.16	Current (1=Strong Buy, 5=Strong Sell)	2.80
Current Year EPS Consensus Estimate	1.24	30 Days Ago	2.80
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.78
Next EPS Report Date	02/24/2012	90 Days Ago	2.78

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	15.80	vs. Previous Year	-32.69%	vs. Previous Year	-20.51%
Trailing 12 Months:	15.18	vs. Previous Quarter	-16.67%	vs. Previous Quarter:	16.61%
PEG Ratio	3.95				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.02	09/30/11	6.83	09/30/11	2.04

Price/Cash Flow	6.57	06/30/11	7.73	06/30/11	2.30
Price / Sales	0.71	03/31/11	7.32	03/31/11	2.11
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.96	09/30/11	0.87	09/30/11	4.72
06/30/11	0.96	06/30/11	0.87	06/30/11	4.96
03/31/11	0.89	03/31/11	0.82	03/31/11	4.52
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	5.69	09/30/11	5.69	09/30/11	19.25
06/30/11	3.52	06/30/11	3.52	06/30/11	19.12
03/31/11	2.82	03/31/11	2.82	03/31/11	18.93
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	37.01	09/30/11	0.96	09/30/11	49.06
06/30/11	40.27	06/30/11	0.97	06/30/11	49.35
03/31/11	42.28	03/31/11	0.95	03/31/11	48.73

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PG&E CORP (NYSE)						**ZACKS RANK: 3 - HOLD**
PCG	40.19	▼-0.67	(-1.64%)	Vol. 2,913,573	15:21 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.

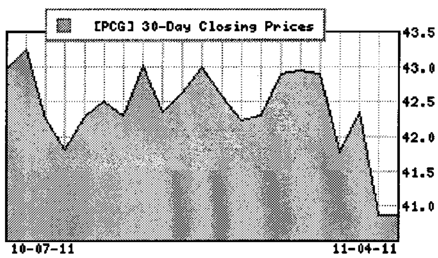
General Information

PG&E CORP
ONE MARKET SPEAR TOWER SUITE 2400
SAN FRANCISCO, CA 94105
Phone: 4152677000
Fax: 415-267-7268
Web: http://www.pgecorp.com
Email: invrel@pge-corp.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/16/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.86
52 Week High	48.63
52 Week Low	37.57
Beta	0.30
20 Day Moving Average	3,231,359.50
Target Price Consensus	44.65



% Price Change		% Price Change Relative to S&P 500	
4 Week	-4.91	4 Week	-12.33
12 Week	2.51	12 Week	-3.58
YTD	-14.59	YTD	-14.29

Share Information		Dividend Information	
Shares Outstanding (millions)	402.24	Dividend Yield	4.45%
		Annual Dividend	$1.82
Market Capitalization (millions)	16,435.73	Payout Ratio	0.54
Short Ratio	1.49	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	09/29/2011 / $0.46

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.83	Current (1=Strong Buy, 5=Strong Sell)	1.87
Current Year EPS Consensus Estimate	3.52	30 Days Ago	1.87
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	1.94
Next EPS Report Date	02/16/2012	90 Days Ago	1.94

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.60	vs. Previous Year	5.88%	vs. Previous Year	9.88%
Trailing 12 Months:	12.09	vs. Previous Quarter	5.88%	vs. Previous Quarter:	4.78%
PEG Ratio	2.32				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.35	09/30/11	11.49	09/30/11	2.91

Price/Cash Flow	4.59	06/30/11	11.40	06/30/11	2.87
Price / Sales	1.11	03/31/11	11.13	03/31/11	2.79
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.86	09/30/11	0.80	09/30/11	9.23
06/30/11	0.87	06/30/11	0.82	06/30/11	9.19
03/31/11	0.70	03/31/11	0.67	03/31/11	9.09
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	9.77	09/30/11	9.77	09/30/11	30.36
06/30/11	10.81	06/30/11	10.81	06/30/11	30.26
03/31/11	11.03	03/31/11	11.03	03/31/11	29.44
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	29.68	09/30/11	1.33	09/30/11	57.05
06/30/11	29.41	06/30/11	0.97	06/30/11	49.26
03/31/11	28.91	03/31/11	0.91	03/31/11	47.64

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PORTLAND GEN ELEC CO (NYSE)						**ZACKS RANK: 3 - HOLD**
POR	25.03	-0.11	(-0.44%)	Vol. 420,406	15:22 ET	

Portland General Electric, headquartered in Portland, Ore., is a vertically integrated electric utility that serves residential, commercial and industrial customers in Oregon. The company has more than a century of experience in power delivery. PGE generates power from a diverse mix of resources, including hydropower, coal and natural gas. PGE also participates in the wholesale market by purchasing and selling electricity and natural gas to utilities and energy marketers.

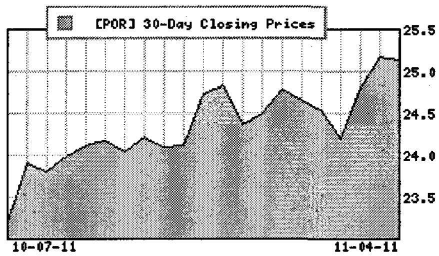
General Information

PORTLAND GEN EL
121 SW SALMON ST 1WTC0501
PORTLAND, OR 97204
Phone: 5034647779
Fax: -
Web: www.portlandgeneral.com
Email: investors@pgn.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/24/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	25.14
52 Week High	26.05
52 Week Low	20.71
Beta	0.66
20 Day Moving Average	774,833.63
Target Price Consensus	26.13



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	8.27	4 Week	-0.18
12 Week	9.26	12 Week	2.77
YTD	15.85	YTD	16.26

Share Information		**Dividend Information**	
Shares Outstanding (millions)	75.34	Dividend Yield	4.22%
		Annual Dividend	$1.06
Market Capitalization (millions)	1,894.07	Payout Ratio	0.55
Short Ratio	3.08	Change in Payout Ratio	-0.02
Last Split Date	N/A	Last Dividend Payout / Amount	09/22/2011 / $0.26

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.39	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	2.01	30 Days Ago	2.44
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.44
Next EPS Report Date	02/24/2012	90 Days Ago	2.67

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	12.54	vs. Previous Year	-44.62%	vs. Previous Year	-5.39%
Trailing 12 Months:	13.16	vs. Previous Quarter	24.14%	vs. Previous Quarter:	6.81%
PEG Ratio	2.51				
Price Ratios		**ROE**		**ROA**	

Price/Book	1.15	09/30/11	8.77	09/30/11	2.60
Price/Cash Flow	5.21	06/30/11	10.19	06/30/11	2.98
Price / Sales	1.06	03/31/11	10.46	03/31/11	3.03
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	-	09/30/11	-	09/30/11	7.99
06/30/11	1.54	06/30/11	1.39	06/30/11	9.10
03/31/11	1.54	03/31/11	1.42	03/31/11	9.19
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	-	09/30/11	-	09/30/11	-
06/30/11	12.51	06/30/11	12.51	06/30/11	21.88
03/31/11	12.54	03/31/11	12.54	03/31/11	21.84
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	-	09/30/11	-	09/30/11	-
06/30/11	16.83	06/30/11	1.09	06/30/11	52.18
03/31/11	16.90	03/31/11	1.09	03/31/11	52.22

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PPL CORP (NYSE)

ZACKS RANK: 3 - HOLD

PPL 29.75 +0.08 (0.27%) Vol. 1,703,780 15:22 ET

PPL Corporation is an energy and utility holding company. PPL controls more than 12,000 megawatts of generating capacity in the United States, sells energy in key U.S. markets and delivers electricity to customers in Pennsylvania and the United Kingdom.

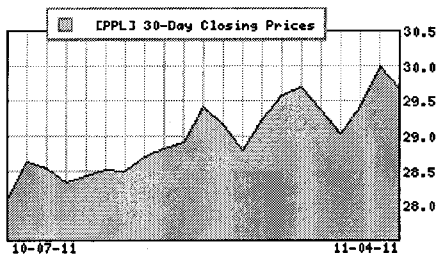
General Information

PPL CORP
TWO N NINTH ST
ALLENTOWN, PA 18101-1179
Phone: 610-774-5151
Fax: 610-774-5106
Web: http://www.pplresources.com
Email: invserv@pplweb.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/10/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	29.67
52 Week High	30.27
52 Week Low	24.10
Beta	0.44
20 Day Moving Average	3,650,914.75
Target Price Consensus	30.4



% Price Change		% Price Change Relative to S&P 500	
4 Week	5.59	4 Week	-2.65
12 Week	14.11	12 Week	7.34
YTD	12.73	YTD	13.13

Share Information		Dividend Information	
Shares Outstanding (millions)	577.75	Dividend Yield	4.72%
		Annual Dividend	$1.40
Market Capitalization (millions)	17,141.81	Payout Ratio	0.48
Short Ratio	3.70	Change in Payout Ratio	-0.08
Last Split Date	08/25/2005	Last Dividend Payout / Amount	09/07/2011 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.62	Current (1=Strong Buy, 5=Strong Sell)	2.08
Current Year EPS Consensus Estimate	2.61	30 Days Ago	2.08
Estimated Long-Term EPS Growth Rate	12.20	60 Days Ago	2.18
Next EPS Report Date	02/10/2012	90 Days Ago	2.25

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.37	vs. Previous Year	2.70%	vs. Previous Year	43.18%
Trailing 12 Months:	10.27	vs. Previous Quarter	68.89%	vs. Previous Quarter:	25.35%
PEG Ratio	0.93				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.54	09/30/11	15.27	09/30/11	4.08

Price/Cash Flow	6.71	06/30/11	15.45	06/30/11	4.28
Price / Sales	1.65	03/31/11	16.50	03/31/11	4.76
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.13	09/30/11	-	09/30/11	14.46
06/30/11	1.17	06/30/11	1.03	06/30/11	15.05
03/31/11	1.17	03/31/11	1.05	03/31/11	16.63
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	18.59	09/30/11	18.59	09/30/11	19.24
06/30/11	17.96	06/30/11	17.96	06/30/11	18.92
03/31/11	17.64	03/31/11	17.64	03/31/11	18.16
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.32	09/30/11	-	09/30/11	-
06/30/11	9.67	06/30/11	1.61	06/30/11	61.62
03/31/11	9.99	03/31/11	1.39	03/31/11	58.19

ZACKS INVESTMENT RESEARCH
Proven Ratings, Research & Recommendations
Zacks.com Quotes and Research

TECO ENERGY INC (NYSE)						**ZACKS RANK: 3 - HOLD**
TE	19.11	▲0.10	(0.53%)	Vol. 1,086,369	15:23 ET	

TECO Energy, Inc. is a diversified, energy-related holding company. Its principal businesses are Tampa Electric, Peoples Gas, Florida's largest natural gas distributor; TECO Power Services, an independent power company; TECO Transport, a river and ocean transportation company; TECO Coal, producer of coal and synthetic fuel; and TECO Solutions, an energy services/engineering company. (Company Press Release)

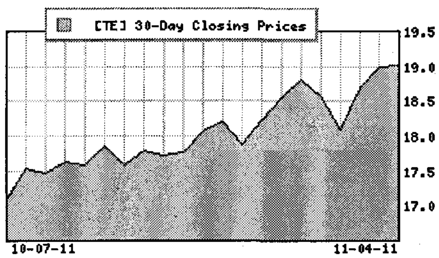
General Information

TECO ENERGY
702 N FRANKLIN ST
TAMPA, FL 33602
Phone: 8132284111
Fax: 813-228-1670
Web: http://www.tecoenergy.com
Email: investorrelations@tecoenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/10/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	19.01
52 Week High	19.66
52 Week Low	15.82
Beta	0.82
20 Day Moving Average	2,160,514.75
Target Price Consensus	18.82



% Price Change		% Price Change Relative to S&P 500	
4 Week	11.23	4 Week	2.56
12 Week	12.42	12 Week	5.74
YTD	6.80	YTD	7.17

Share Information		Dividend Information	
Shares Outstanding (millions)	215.72	Dividend Yield	4.52%
		Annual Dividend	$0.86
Market Capitalization (millions)	4,100.90	Payout Ratio	0.69
Short Ratio	2.61	Change in Payout Ratio	-0.06
Last Split Date	08/31/1993	Last Dividend Payout / Amount	08/11/2011 / $0.22

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.29	Current (1=Strong Buy, 5=Strong Sell)	2.69
Current Year EPS Consensus Estimate	1.31	30 Days Ago	2.81
Estimated Long-Term EPS Growth Rate	4.70	60 Days Ago	2.81
Next EPS Report Date	02/10/2012	90 Days Ago	2.81

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.50	vs. Previous Year	23.53%	vs. Previous Year	1.06%
Trailing 12 Months:	15.21	vs. Previous Quarter	16.67%	vs. Previous Quarter:	2.90%
PEG Ratio	3.11				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.81	09/30/11	12.15	09/30/11	3.74

Price/Cash Flow	6.94	06/30/11	11.56	06/30/11	3.50
Price / Sales	1.22	03/31/11	11.77	03/31/11	3.49
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.83	09/30/11	0.63	09/30/11	7.97
06/30/11	0.90	06/30/11	0.61	06/30/11	7.51
03/31/11	0.98	03/31/11	0.64	03/31/11	7.54
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	12.89	09/30/11	12.89	09/30/11	10.49
06/30/11	12.19	06/30/11	12.19	06/30/11	10.31
03/31/11	11.85	03/31/11	11.85	03/31/11	10.17
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.45	09/30/11	1.19	09/30/11	54.32
06/30/11	9.29	06/30/11	1.33	06/30/11	57.09
03/31/11	9.27	03/31/11	1.41	03/31/11	58.42

ZACKS INVESTMENT RESEARCH
Proven Ratings, Research & Recommendations
Zacks.com Quotes and Research

WESTAR ENERGY INC (NYSE)

ZACKS RANK: 3 - HOLD

WR 27.29 +0.02 (0.07%) Vol. 1,371,210 15:24 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.

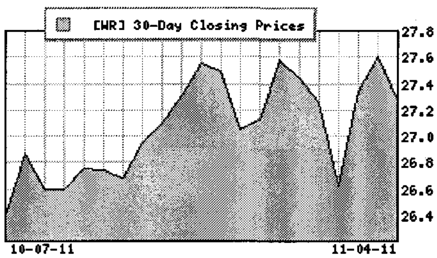
General Information

WESTAR ENERGY
818 KANSAS AVE
TOPEKA, KS 66601
Phone: 7855756300
Fax: 785-575-6596
Web: http://www.westarenergy.com
Email: ir@westarenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/23/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	27.27
52 Week High	27.98
52 Week Low	22.63
Beta	0.59
20 Day Moving Average	1,164,479.38
Target Price Consensus	28.58



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.30	4 Week	-4.76
12 Week	11.03	12 Week	4.44
YTD	8.39	YTD	8.77

Share Information		Dividend Information	
Shares Outstanding (millions)	115.81	Dividend Yield	4.69%
		Annual Dividend	$1.28
Market Capitalization (millions)	3,158.22	Payout Ratio	0.99
Short Ratio	7.76	Change in Payout Ratio	0.22
Last Split Date	N/A	Last Dividend Payout / Amount	09/07/2011 / $0.32

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.11	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	1.77	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	6.10	60 Days Ago	2.00
Next EPS Report Date	02/23/2012	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.41	vs. Previous Year	-3.92%	vs. Previous Year	5.23%
Trailing 12 Months:	21.14	vs. Previous Quarter	-%	vs. Previous Quarter:	29.20%
PEG Ratio	2.53				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.22	09/30/11	7.92	09/30/11	2.37

Price/Cash Flow	6.25	06/30/11	8.10	06/30/11	2.41
Price / Sales	1.47	03/31/11	8.63	03/31/11	2.57
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.68	09/30/11	0.45	09/30/11	9.12
06/30/11	0.68	06/30/11	0.45	06/30/11	9.28
03/31/11	0.67	03/31/11	0.41	03/31/11	9.86
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	14.69	09/30/11	14.69	09/30/11	22.42
06/30/11	13.48	06/30/11	13.48	06/30/11	21.72
03/31/11	14.18	03/31/11	14.18	03/31/11	21.26
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	5.46	09/30/11	1.06	09/30/11	51.16
06/30/11	5.40	06/30/11	1.12	06/30/11	52.57
03/31/11	5.38	03/31/11	1.14	03/31/11	53.15

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Zacks.com Quotes and Research

WISCONSIN ENERGY CORP (NYSE)

ZACKS RANK: 2 - BUY

WEC 32.82 ▲0.10 (0.31%) Vol. 748,059 15:24 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

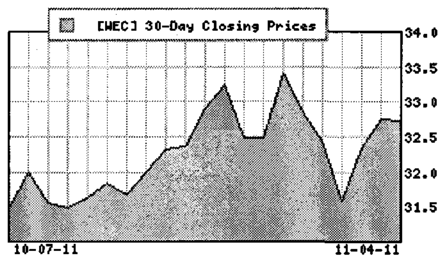
WISC ENERGY CP
231 W MICHIGAN ST .P O BOX 1331
MILWAUKEE, WI 53201
Phone: 414-221-2345
Fax: -
Web: http://www.wisconsinenergy.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/07/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.72
52 Week High	33.63
52 Week Low	27.00
Beta	0.33
20 Day Moving Average	1,658,206.38
Target Price Consensus	34.44



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.91	4 Week	-4.20
12 Week	10.09	12 Week	3.56
YTD	11.18	YTD	11.57

Share Information		Dividend Information	
Shares Outstanding (millions)	233.74	Dividend Yield	3.18%
		Annual Dividend	$1.04
Market Capitalization (millions)	7,647.97	Payout Ratio	0.47
Short Ratio	3.46	Change in Payout Ratio	0.05
Last Split Date	03/02/2011	Last Dividend Payout / Amount	08/10/2011 / $0.26

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.50	Current (1=Strong Buy, 5=Strong Sell)	2.14
Current Year EPS Consensus Estimate	2.15	30 Days Ago	2.14
Estimated Long-Term EPS Growth Rate	7.50	60 Days Ago	2.14
Next EPS Report Date	02/07/2012	90 Days Ago	2.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.22	vs. Previous Year	15.79%	vs. Previous Year	8.18%
Trailing 12 Months:	14.81	vs. Previous Quarter	34.15%	vs. Previous Quarter:	6.16%
PEG Ratio	2.03				

Price Ratios **ROE** **ROA**

Price/Book	1.94	09/30/11	13.45	09/30/11	3.99
Price/Cash Flow	13.34	06/30/11	13.18	06/30/11	3.90
Price / Sales	1.71	03/31/11	13.14	03/31/11	3.84
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.04	09/30/11	0.70	09/30/11	11.75
06/30/11	1.02	06/30/11	0.73	06/30/11	11.56
03/31/11	1.09	03/31/11	0.88	03/31/11	11.59
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	17.92	09/30/11	17.92	09/30/11	16.86
06/30/11	17.69	06/30/11	17.69	06/30/11	16.89
03/31/11	17.84	03/31/11	17.84	03/31/11	16.70
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.24	09/30/11	1.17	09/30/11	53.77
06/30/11	8.90	06/30/11	1.10	06/30/11	52.15
03/31/11	8.49	03/31/11	1.11	03/31/11	52.44

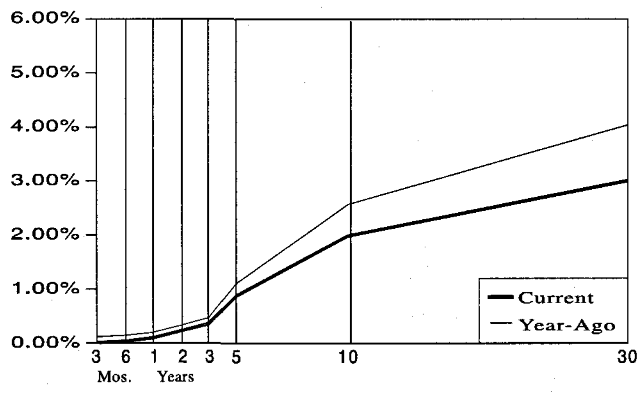
ATTACHMENT C

Selected Yields

	Recent (11/02/11)	3 Months Ago (8/03/11)	Year Ago (11/03/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.51	0.28	0.23
3-month LIBOR	0.43	0.27	0.29
Bank CDs			
6-month	0.17	0.26	0.32
1-year	0.21	0.44	0.53
5-year	1.14	1.62	1.57
U.S. Treasury Securities			
3-month	0.01	0.01	0.12
6-month	0.04	0.08	0.15
1-year	0.10	0.14	0.20
5-year	0.88	1.26	1.11
10-year	1.99	2.62	2.57
10-year (inflation-protected)	-0.10	0.28	0.42
30-year	3.01	3.90	4.04
30-year Zero	3.22	4.27	4.43

	Recent (11/02/11)	3 Months Ago (8/03/11)	Year Ago (11/03/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.62	1.82	1.23
FHLMC 5.5% (Gold)	2.34	2.43	1.51
FNMA 5.5%	2.10	2.36	1.27
FNMA ARM	2.43	2.49	2.81
Corporate Bonds			
Financial (10-year) A	4.15	4.09	3.99
Industrial (25/30-year) A	4.18	4.93	5.28
Utility (25/30-year) A	4.12	4.87	5.35
Utility (25/30-year) Baa/BBB	4.76	5.43	5.79
Foreign Bonds (10-Year)			
Canada	2.17	2.67	2.87
Germany	1.83	2.40	2.42
Japan	1.00	1.02	0.95
United Kingdom	2.29	2.74	3.15
Preferred Stocks			
Utility A	5.82	6.05	5.77
Financial A	6.57	6.33	6.48
Financial Adjustable A	5.50	5.50	5.50

Treasury Security Yield Curve



	Recent (11/02/11)	3 Months Ago (8/03/11)	Year Ago (11/03/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.12	4.47	3.96
25-Bond Index (Revs)	5.10	5.62	4.67
General Obligation Bonds (GOs)			
1-year Aaa	0.24	0.21	0.32
1-year A	1.05	0.96	1.13
5-year Aaa	1.28	1.20	1.31
5-year A	2.35	2.18	2.26
10-year Aaa	2.57	2.87	2.71
10-year A	3.56	4.18	3.86
25/30-year Aaa	4.03	4.28	4.23
25/30-year A	5.37	5.77	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.55	4.83	4.63
Electric AA	4.90	5.16	4.65
Housing AA	5.59	5.80	5.50
Hospital AA	4.94	5.08	4.84
Toll Road Aaa	4.55	4.90	4.64

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

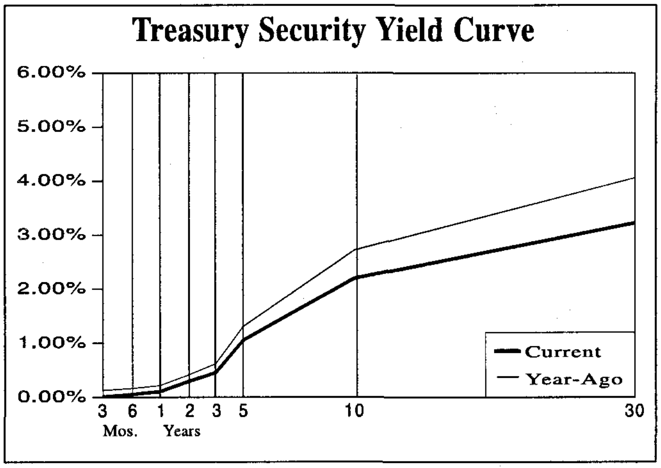
	Recent Levels			Average Levels Over the Last...		
	10/19/11	10/5/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1571895	1541640	30255	1573995	1556283	1339026
Borrowed Reserves	11317	11429	-112	11732	13270	23713
Net Free/Borrowed Reserves	1560578	1530211	30367	1562263	1543014	1315313

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/17/11	10/10/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2150.9	2157.9	-7.0	40.8%	30.1%	21.0%
M2 (M1+savings+small time deposits)	9628.7	9622.4	6.3	16.0%	15.7%	10.2%

Selected Yields

	Recent (10/26/11)	3 Months Ago (7/27/11)	Year Ago (10/27/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.49	0.22	0.23
3-month LIBOR	0.42	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.32
1-year	0.21	0.44	0.54
5-year	1.14	1.62	1.61
U.S. Treasury Securities			
3-month	0.01	0.08	0.13
6-month	0.06	0.12	0.17
1-year	0.11	0.20	0.22
5-year	1.06	1.52	1.31
10-year	2.20	2.98	2.72
10-year (inflation-protected)	0.12	0.46	0.56
30-year	3.22	4.29	4.06
30-year Zero	3.43	4.69	4.40
Mortgage-Backed Securities			
GNMA 5.5%	1.76	2.04	1.22
FHLMC 5.5% (Gold)	2.39	2.68	1.69
FNMA 5.5%	2.19	2.58	1.53
FNMA ARM	2.47	2.51	2.86
Corporate Bonds			
Financial (10-year) A	4.41	4.42	4.22
Industrial (25/30-year) A	4.49	5.30	5.28
Utility (25/30-year) A	4.41	5.28	5.31
Utility (25/30-year) Baa/BBB	5.05	5.82	5.86
Foreign Bonds (10-Year)			
Canada	2.38	2.88	2.89
Germany	2.04	2.65	2.57
Japan	1.00	1.09	0.96
United Kingdom	2.47	2.98	3.15
Preferred Stocks			
Utility A	5.21	5.14	5.79
Financial A	6.49	6.07	6.05
Financial Adjustable A	5.50	5.50	5.50
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.08	4.46	3.84
25-Bond Index (Revs)	5.07	5.32	4.60
General Obligation Bonds (GOs)			
1-year Aaa	0.29	0.21	0.34
1-year A	1.00	1.01	1.13
5-year Aaa	1.41	1.27	1.28
5-year A	2.42	2.27	2.24
10-year Aaa	2.69	2.92	2.64
10-year A	3.60	4.23	3.77
25/30-year Aaa	4.10	4.34	4.21
25/30-year A	5.42	5.83	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.56	4.87	4.63
Electric AA	4.94	5.19	4.65
Housing AA	5.66	5.84	5.52
Hospital AA	4.97	5.12	4.80
Toll Road Aaa	4.57	4.92	4.62



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/19/11	10/5/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1572296	1541887	30409	1574153	1556363	1339067
Borrowed Reserves	11317	11429	-112	11732	13270	23713
Net Free/Borrowed Reserves	1560979	1530458	30521	1562421	1543093	1315354

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

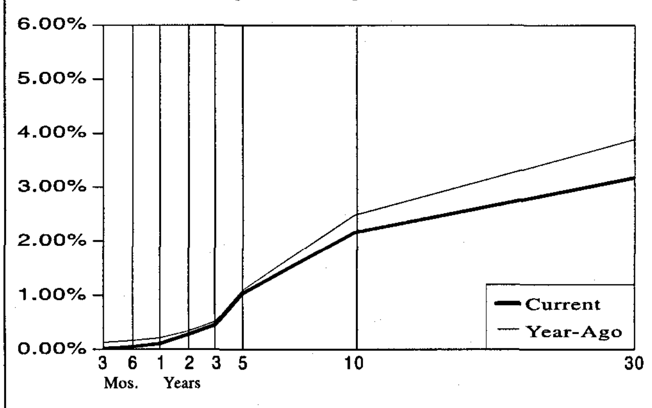
	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/10/11	10/3/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2152.4	2192.5	-40.1	41.1%	30.9%	20.1%
M2 (M1+savings+small time deposits)	9621.4	9604.8	16.6	17.3%	15.8%	10.2%

Selected Yields

	Recent (10/19/11)	3 Months Ago (7/20/11)	Year Ago (10/20/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.44	0.21	0.23
3-month LIBOR	0.41	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.32
1-year	0.21	0.45	0.54
5-year	1.14	1.62	1.61
U.S. Treasury Securities			
3-month	0.02	0.02	0.13
6-month	0.05	0.07	0.17
1-year	0.11	0.16	0.21
5-year	1.04	1.47	1.10
10-year	2.16	2.93	2.48
10-year (inflation-protected)	0.20	0.54	0.42
30-year	3.18	4.25	3.89
30-year Zero	3.38	4.65	4.25

	Recent (10/19/11)	3 Months Ago (7/20/11)	Year Ago (10/20/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.84	2.06	1.29
FHLMC 5.5% (Gold)	2.36	2.64	1.68
FNMA 5.5%	2.17	2.55	1.52
FNMA ARM	2.47	2.51	2.86
Corporate Bonds			
Financial (10-year) A	4.33	4.45	4.09
Industrial (25/30-year) A	4.53	5.32	5.14
Utility (25/30-year) A	4.40	5.27	5.22
Utility (25/30-year) Baa/BBB	4.92	5.78	5.72
Foreign Bonds (10-Year)			
Canada	2.33	2.95	2.75
Germany	2.06	2.77	2.44
Japan	1.02	1.09	0.90
United Kingdom	2.47	3.07	2.99
Preferred Stocks			
Utility A	5.25	5.12	5.79
Financial A	6.69	6.07	6.59
Financial Adjustable A	5.49	5.49	5.49

Treasury Security Yield Curve



	Recent (10/19/11)	3 Months Ago (7/20/11)	Year Ago (10/20/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.17	4.51	3.82
25-Bond Index (Revs)	5.06	5.30	4.57
General Obligation Bonds (GOs)			
1-year Aaa	0.25	0.20	0.33
1-year A	1.08	1.04	1.11
5-year Aaa	1.39	1.27	1.25
5-year A	2.40	2.34	2.22
10-year Aaa	2.69	2.91	2.56
10-year A	3.67	4.24	3.66
25/30-year Aaa	4.09	4.34	4.17
25/30-year A	5.45	5.85	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.56	4.87	4.63
Electric AA	4.94	5.19	4.65
Housing AA	5.64	5.80	5.53
Hospital AA	4.97	5.12	4.82
Toll Road Aaa	4.57	4.92	4.62

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

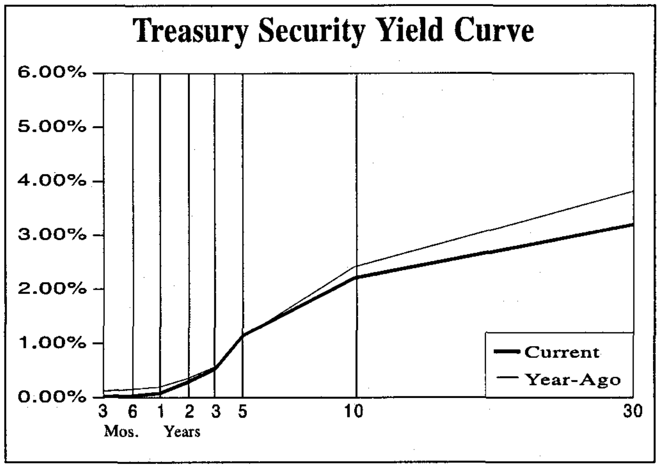
	Recent Levels			Average Levels Over the Last...		
	10/5/11	9/21/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1541886	1548766	-6880	1583023	1546301	1316519
Borrowed Reserves	11429	11614	-185	11920	13833	25141
Net Free/Borrowed Reserves	1530457	1537152	-6695	1571103	1532469	1291378

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/3/11	9/26/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2182.8	2134.4	48.4	43.1%	31.8%	22.6%
M2 (M1+savings+small time deposits)	9617.9	9601.7	16.2	16.8%	15.8%	10.3%

Selected Yields

	Recent (10/12/11)	3 Months Ago (7/13/11)	Year Ago (10/13/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.38	0.23	0.24
3-month LIBOR	0.40	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.32
1-year	0.21	0.44	0.56
5-year	1.14	1.61	1.66
U.S. Treasury Securities			
3-month	0.02	0.03	0.12
6-month	0.04	0.05	0.16
1-year	0.08	0.15	0.20
5-year	1.15	1.44	1.12
10-year	2.21	2.88	2.42
10-year (inflation-protected)	0.23	0.52	0.36
30-year	3.20	4.17	3.82
30-year Zero	3.39	4.55	4.16



	Recent (10/12/11)	3 Months Ago (7/13/11)	Year Ago (10/13/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.89	2.11	1.27
FHLMC 5.5% (Gold)	2.32	2.66	1.74
FNMA 5.5%	2.17	2.56	1.58
FNMA ARM	2.47	2.51	2.86
Corporate Bonds			
Financial (10-year) A	4.37	4.37	3.96
Industrial (25/30-year) A	4.59	5.26	5.01
Utility (25/30-year) A	4.53	5.20	5.02
Utility (25/30-year) Baa/BBB	4.99	5.75	5.56
Foreign Bonds (10-Year)			
Canada	2.35	2.93	2.73
Germany	2.19	2.75	2.28
Japan	1.00	1.11	0.88
United Kingdom	2.64	3.12	2.88
Preferred Stocks			
Utility A	5.57	5.22	5.76
Financial A	6.81	6.03	6.38
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.14	4.65	3.84
25-Bond Index (Revs)	5.04	5.36	4.58
General Obligation Bonds (GOs)			
1-year Aaa	0.26	0.20	0.34
1-year A	1.11	1.04	1.14
5-year Aaa	1.41	1.32	1.28
5-year A	2.43	2.40	2.22
10-year Aaa	2.63	2.90	2.58
10-year A	3.75	4.20	3.71
25/30-year Aaa	4.12	4.34	4.15
25/30-year A	5.50	5.85	5.40
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.59	4.87	4.61
Electric AA	4.97	5.19	4.63
Housing AA	5.63	5.84	5.50
Hospital AA	5.00	5.13	4.81
Toll Road Aaa	4.60	4.93	4.60

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/5/11	9/21/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1541919	1548799	-6880	1583036	1546308	1316523
Borrowed Reserves	11429	11614	-185	11920	13833	25141
Net Free/Borrowed Reserves	1530490	1537185	-6695	1571116	1532476	1291381

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

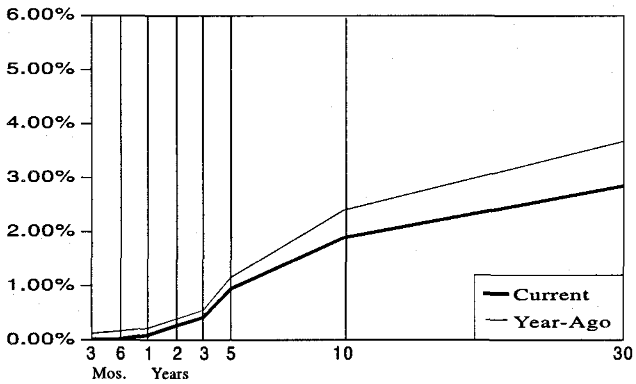
	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/26/11	9/19/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2136.9	2105.7	31.2	44.4%	26.2%	20.6%
M2 (M1+savings+small time deposits)	9603.6	9569.8	33.8	20.6%	16.1%	10.1%

Selected Yields

	Recent (10/05/11)	3 Months Ago (7/06/11)	Year Ago (10/06/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.41	0.18	0.27
3-month LIBOR	0.38	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.33
1-year	0.21	0.44	0.57
5-year	1.18	1.63	1.68
U.S. Treasury Securities			
3-month	0.01	0.01	0.12
6-month	0.02	0.05	0.17
1-year	0.09	0.17	0.22
5-year	0.95	1.66	1.16
10-year	1.89	3.11	2.40
10-year (inflation-protected)	0.08	0.68	0.46
30-year	2.85	4.36	3.68
30-year Zero	3.03	4.75	3.98

	Recent (10/05/11)	3 Months Ago (7/06/11)	Year Ago (10/06/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.54	2.32	1.65
FHLMC 5.5% (Gold)	2.23	2.91	2.16
FNMA 5.5%	2.13	2.81	2.02
FNMA ARM	2.47	2.51	2.86
Corporate Bonds			
Financial (10-year) A	3.88	4.55	3.93
Industrial (25/30-year) A	4.29	5.44	4.92
Utility (25/30-year) A	4.21	5.40	4.91
Utility (25/30-year) Baa/BBB	4.65	5.93	5.45
Foreign Bonds (10-Year)			
Canada	2.14	3.04	2.74
Germany	1.84	2.93	2.22
Japan	0.97	1.18	0.85
United Kingdom	2.36	3.25	2.90
Preferred Stocks			
Utility A	5.29	5.17	6.08
Financial A	6.51	6.03	6.43
Financial Adjustable A	5.48	5.48	5.48

Treasury Security Yield Curve



	Recent (10/05/11)	3 Months Ago (7/06/11)	Year Ago (10/06/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.93	4.59	3.84
25-Bond Index (Revs)	5.01	5.34	4.59
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.23	0.32
1-year A	0.97	1.02	1.12
5-year Aaa	1.13	1.33	1.33
5-year A	2.18	2.45	2.28
10-year Aaa	2.36	2.75	2.61
10-year A	3.47	4.20	3.77
25/30-year Aaa	3.88	4.39	4.16
25/30-year A	5.53	5.86	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.56	4.89	4.62
Electric AA	4.92	5.21	4.63
Housing AA	5.55	5.85	5.52
Hospital AA	4.92	5.25	4.81
Toll Road Aaa	4.58	4.99	4.61

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/21/11	9/7/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1548799	1568587	-19788	1586683	1533774	1295559
Borrowed Reserves	11614	11685	-71	12154	14440	26668
Net Free/Borrowed Reserves	1537185	1556902	-19717	1574529	1519335	1268891

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/19/11	9/12/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2105.7	2106.1	-0.4	38.8%	24.1%	19.2%
M2 (M1+savings+small time deposits)	9569.8	9583.9	-14.1	23.0%	15.2%	10.1%

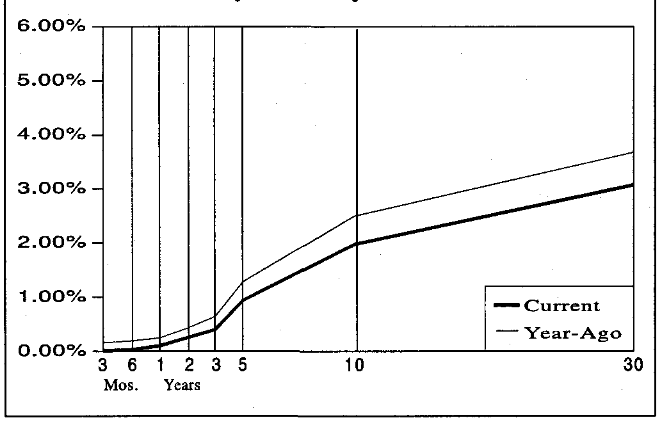
Selected Yields

TAXABLE

	Recent (9/28/11)	3 Months Ago (6/29/11)	Year Ago (9/29/10)
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.42	0.17	0.22
3-month LIBOR	0.37	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.33
1-year	0.21	0.44	0.57
5-year	1.26	1.64	1.68
U.S. Treasury Securities			
3-month	0.01	0.02	0.16
6-month	0.03	0.10	0.19
1-year	0.10	0.19	0.25
5-year	0.94	1.69	1.28
10-year	1.98	3.11	2.50
10-year (inflation-protected)	0.11	0.67	0.69
30-year	3.07	4.38	3.68
30-year Zero	3.28	4.76	3.96

	Recent (9/28/11)	3 Months Ago (6/29/11)	Year Ago (9/29/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.62	2.02	2.01
FHLMC 5.5% (Gold)	2.08	2.63	2.33
FNMA 5.5%	1.97	2.50	2.14
FNMA ARM	2.50	2.51	2.90
Corporate Bonds			
Financial (10-year) A	3.87	4.58	4.01
Industrial (25/30-year) A	4.50	5.47	4.89
Utility (25/30-year) A	4.34	5.42	4.94
Utility (25/30-year) Baa/BBB	4.98	5.92	5.46
Foreign Bonds (10-Year)			
Canada	2.20	3.09	2.74
Germany	2.01	2.98	2.24
Japan	1.00	1.13	0.93
United Kingdom	2.55	3.33	2.91
Preferred Stocks			
Utility A	5.24	5.13	6.08
Financial A	6.45	6.02	6.50
Financial Adjustable A	5.48	5.48	5.48

Treasury Security Yield Curve



TAX-EXEMPT

	Recent (9/28/11)	3 Months Ago (6/29/11)	Year Ago (9/29/10)
Bond Buyer Indexes			
20-Bond Index (GOs)	3.85	4.46	3.83
25-Bond Index (Revs)	4.96	5.31	4.58
General Obligation Bonds (GOs)			
1-year Aaa	0.24	0.24	0.34
1-year A	0.99	1.04	1.15
5-year Aaa	1.04	1.25	1.22
5-year A	2.05	2.41	2.20
10-year Aaa	2.15	2.63	2.51
10-year A	3.42	4.11	3.65
25/30-year Aaa	3.87	4.36	4.11
25/30-year A	5.53	5.86	5.40
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.56	4.87	4.61
Electric AA	4.92	5.17	4.62
Housing AA	5.55	5.79	5.49
Hospital AA	4.90	5.25	4.81
Toll Road Aaa	4.58	4.97	4.60

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/21/11	9/7/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1548803	1568589	-19786	1586684	1533775	1295560
Borrowed Reserves	11614	11685	-71	12154	14440	26668
Net Free/Borrowed Reserves	1537189	1556904	-19715	1574530	1519335	1268892

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

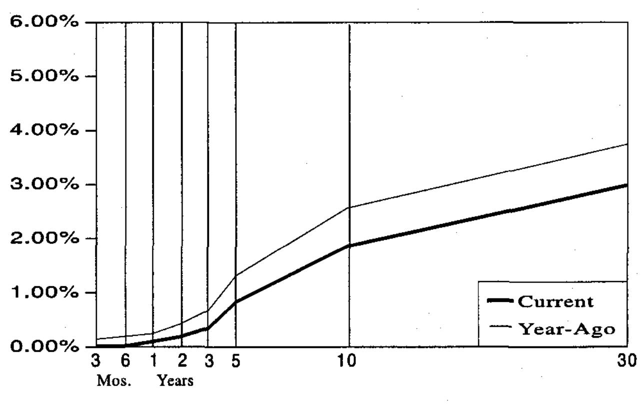
	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/12/11	9/5/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2106.6	2136.3	-29.7	42.0%	27.6%	18.9%
M2 (M1+savings+small time deposits)	9583.6	9591.1	-7.5	25.4%	15.7%	10.3%

Selected Yields

	Recent (9/21/11)	3 Months Ago (6/22/11)	Year Ago (9/22/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.42	0.18	0.24
3-month LIBOR	0.36	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.34
1-year	0.21	0.44	0.60
5-year	1.26	1.64	1.71
U.S. Treasury Securities			
3-month	0.01	0.01	0.15
6-month	0.02	0.08	0.19
1-year	0.10	0.15	0.25
5-year	0.84	1.54	1.32
10-year	1.86	2.98	2.56
10-year (inflation-protected)	0.00	0.75	0.65
30-year	2.99	4.22	3.75
30-year Zero	3.25	4.60	4.02

	Recent (9/21/11)	3 Months Ago (6/22/11)	Year Ago (9/22/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.14	2.05	1.99
FHLMC 5.5% (Gold)	1.93	2.55	2.39
FNMA 5.5%	1.85	2.43	2.27
FNMA ARM	2.50	2.51	2.90
Corporate Bonds			
Financial (10-year) A	3.59	4.42	4.11
Industrial (25/30-year) A	4.31	5.31	5.02
Utility (25/30-year) A	4.23	5.29	5.04
Utility (25/30-year) Baa/BBB	4.86	5.79	5.56
Foreign Bonds (10-Year)			
Canada	2.12	2.97	2.86
Germany	1.77	2.94	2.35
Japan	0.99	1.12	1.03
United Kingdom	2.41	3.19	2.97
Preferred Stocks			
Utility A	5.23	5.27	6.08
Financial A	6.38	6.10	6.47
Financial Adjustable A	5.47	5.47	5.47

Treasury Security Yield Curve



	Recent (9/21/11)	3 Months Ago (6/22/11)	Year Ago (9/22/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.07	4.49	3.89
25-Bond Index (Revs)	5.11	5.32	4.63
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.28	0.34
1-year A	0.99	1.08	1.15
5-year Aaa	1.00	1.37	1.24
5-year A	1.99	2.40	2.24
10-year Aaa	2.21	2.63	2.56
10-year A	3.56	4.08	3.70
25/30-year Aaa	3.89	4.37	4.11
25/30-year A	5.63	5.89	5.40
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.62	4.87	4.61
Electric AA	4.97	5.19	4.62
Housing AA	5.60	5.79	5.44
Hospital AA	4.97	5.28	4.82
Toll Road Aaa	4.69	4.97	4.60

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/7/11	8/24/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1568590	1577802	-9212	1595396	1515698	1275488
Borrowed Reserves	11685	11833	-148	12407	15069	28273
Net Free/Borrowed Reserves	1556905	1565969	-9064	1582989	1500629	1247215

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

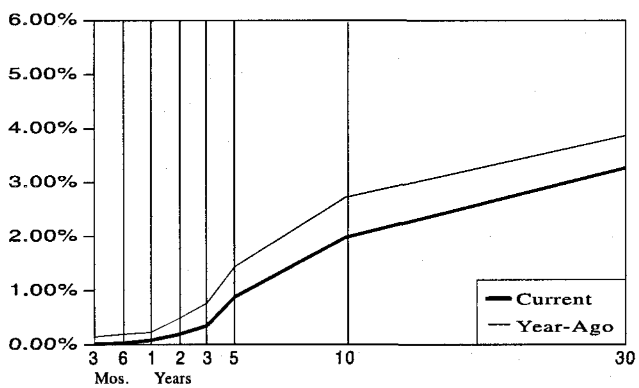
	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/5/11	8/29/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2136.6	2124.1	12.5	48.8%	30.8%	21.9%
M2 (M1+savings+small time deposits)	9591.4	9570.1	21.3	26.4%	15.3%	10.5%

Selected Yields

	Recent (9/15/11)	3 Months Ago (6/15/11)	Year Ago (9/15/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.38	0.17	0.24
3-month LIBOR	0.35	0.25	0.29
Bank CDs			
6-month	0.17	0.27	0.35
1-year	0.21	0.45	0.61
5-year	1.29	1.69	1.71
U.S. Treasury Securities			
3-month	0.01	0.05	0.15
6-month	0.03	0.10	0.19
1-year	0.08	0.16	0.23
5-year	0.88	1.55	1.44
10-year	1.98	2.97	2.72
10-year (inflation-protected)	0.06	0.69	0.93
30-year	3.27	4.20	3.87
30-year Zero	3.58	4.57	4.15

	Recent (9/15/11)	3 Months Ago (6/15/11)	Year Ago (9/15/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.13	2.11	1.90
FHLMC 5.5% (Gold)	1.97	2.56	2.35
FNMA 5.5%	1.88	2.45	2.17
FNMA ARM	2.50	2.51	2.90
Corporate Bonds			
Financial (10-year) A	3.72	4.84	4.23
Industrial (25/30-year) A	4.60	5.28	5.02
Utility (25/30-year) A	4.48	5.25	5.06
Utility (25/30-year) Baa/BBB	5.07	5.77	5.58
Foreign Bonds (10-Year)			
Canada	2.20	2.95	2.96
Germany	1.88	2.95	2.40
Japan	1.00	1.17	1.05
United Kingdom	2.44	3.24	3.08
Preferred Stocks			
Utility A	5.25	5.77	6.08
Financial A	6.38	6.10	6.81
Financial Adjustable A	5.46	5.46	5.46

Treasury Security Yield Curve



	Recent (9/15/11)	3 Months Ago (6/15/11)	Year Ago (9/15/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.05	4.49	3.92
25-Bond Index (Revs)	5.07	5.34	4.65
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.25	0.31
1-year A	0.98	1.07	1.14
5-year Aaa	0.93	1.31	1.21
5-year A	1.96	2.40	2.25
10-year Aaa	2.17	2.64	2.45
10-year A	3.65	4.08	3.69
25/30-year Aaa	3.88	4.38	4.06
25/30-year A	5.62	5.89	5.40
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.62	4.87	4.62
Electric AA	4.97	5.18	4.62
Housing AA	5.60	5.59	5.39
Hospital AA	4.97	5.29	4.87
Toll Road Aaa	4.69	4.97	4.60

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/7/11	**8/24/11**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1568589	1577800	-9211	1595396	1515698	1275488
Borrowed Reserves	11685	11833	-148	12407	15069	28273
Net Free/Borrowed Reserves	1556904	1565967	-9063	1582989	1500629	1247215

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	8/29/11	**8/22/11**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2124.1	2102.8	21.3	38.8%	25.1%	20.8%
M2 (M1+savings+small time deposits)	9570.1	9539.7	30.4	25.7%	15.1%	10.3%

ATTACHMENT D

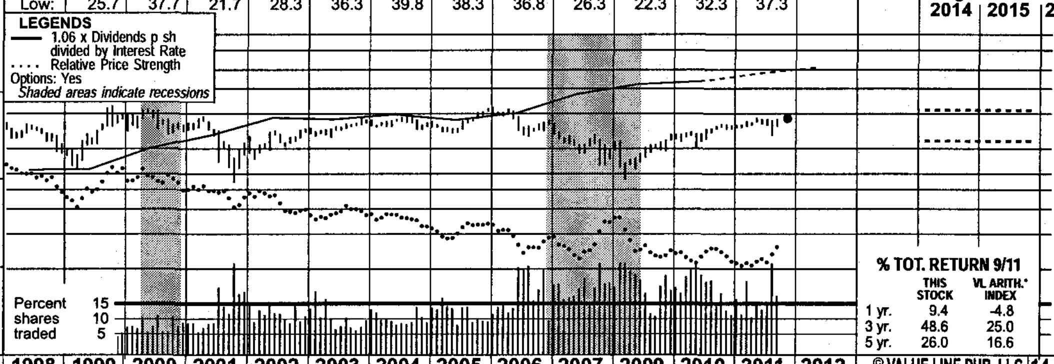
PINNACLE WEST NYSE-PNW

RECENT PRICE 45.43 | P/E RATIO 15.7 (Trailing: 16.3 Median: 14.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 3 Raised 1/29/10
SAFETY 2 Raised 5/6/11
TECHNICAL 3 Lowered 9/16/11
BETA .70 (1.00 = Market)

High:	52.7	50.7	46.7	40.5	45.8	46.7	51.0	51.7	42.9	38.0	42.7	46.4	
Low:	25.7	37.7	21.7	28.3	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	

Target Price Range
2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	7%
Low	35	(-25%)	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	0	0	0	0	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	127	126	144
to Sell	151	149	146
Hld's(000)	77797	79145	81484

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.4	-4.8
3 yr.	48.6	25.0
5 yr.	26.0	16.6

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
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	32.50	30.01	**29.75**	**31.80**	Revenues per sh	**31.25**
5.09	5.16	5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.08	6.85	**6.80**	**7.55**	"Cash Flow" per sh	**8.00**
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	2.26	3.08	**2.75**	**3.25**	Earnings per sh A	**3.50**
.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	**2.10**	**2.10**	Div'd Decl'd per sh B ■	**2.30**
2.92	3.38	2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	7.64	7.03	**9.15**	**9.85**	Cap'l Spending per sh	**8.25**
20.32	21.49	22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	32.69	33.86	**34.50**	**35.60**	Book Value per sh C	**39.25**
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	101.43	108.77	**109.25**	**110.00**	Common Shs Outst'g D	**123.00**
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	13.7	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	**12.0**
.63	.72	.74	.68	.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	.91	.80	*Value Line*		Relative P/E Ratio	**.80**
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%	6.8%	5.4%	*estimates*		Avg Ann'l Div'd Yield	**5.5%**

CAPITAL STRUCTURE as of 6/30/11
Total Debt $3672.5 mill. **Due in 5 Yrs** $2071.2 mill.
LT Debt $2761.7 mill. **LT Interest** $167.1 mill.
Incl. $83.1 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $24.0 mill.
Pension Assets-12/10 $1.78 bill.
Oblig. $2.35 bill.
Pfd Stock None

Common Stock 109,110,950 shs.
as of 7/26/11
MARKET CAP: $5.0 billion (Large Cap)

2000	2001	2002	2003	2004	2005	2006	2007	2009	2010	2011	2012		14-16
3690.2	4551.4	2637.3	2817.9	2899.7	2988.0	3401.7	3523.6	3297.1	3263.6	**3250**	**3500**	Revenues ($mill)	**3850**
283.6	312.2	215.2	230.6	235.2	223.2	317.1	298.8	229.2	330.4	**300**	**360**	Net Profit ($mill)	**430**
44.1%	40.6%	39.1%	31.4%	35.4%	36.2%	33.0%	33.6%	36.9%	31.9%	**34.0%**	**34.5%**	Income Tax Rate	**34.5%**
7.6%	15.3%	20.5%	6.2%	6.9%	10.4%	11.1%	14.8%	11.2%	11.7%	**13.0%**	**13.0%**	AFUDC % to Net Profit	**9.0%**
45.1%	51.7%	51.8%	50.6%	46.7%	43.2%	48.4%	47.0%	50.4%	45.3%	**49.0%**	**52.0%**	Long-Term Debt Ratio	**46.0%**
54.9%	48.3%	48.2%	49.4%	53.3%	56.8%	51.6%	53.0%	49.6%	54.7%	**51.0%**	**48.0%**	Common Equity Ratio	**54.0%**
4337.8	5172.4	5567.9	5727.5	5535.2	6033.4	6678.7	6658.7	6686.6	6729.1	**7415**	**8150**	Total Capital ($mill)	**8950**
5133.2	5907.3	6479.4	7480.1	7535.5	7577.1	7881.9	8436.4	9257.8	9578.8	**10135**	**10750**	Net Plant ($mill)	**12200**
8.1%	7.6%	5.4%	5.5%	5.6%	5.0%	6.2%	5.9%	4.8%	6.5%	**5.5%**	**6.0%**	Return on Total Cap'l	**6.5%**
11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.9%	9.0%	**8.0%**	**9.0%**	Return on Shr. Equity	**9.0%**
11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.9%	9.0%	**8.0%**	**9.0%**	Return on Com Equity E	**9.0%**
6.8%	7.3%	2.9%	2.6%	2.3%	1.0%	3.4%	2.5%	.7%	3.1%	**2.0%**	**3.5%**	Retained to Com Eq	**3.0%**
43%	41%	64%	68%	71%	85%	63%	70%	89%	66%	**76%**	**64%**	All Div'ds to Net Prof	**65%**

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.3	-2.2	-1.6
Avg. Indust. Use (MWH)	665	619	619
Avg. Indust. Revs. per KWH (¢)	7.91	8.11	7.83
Capacity at Peak (Mw)	8457	8635	8682
Peak Load, Summer (Mw)	7026	7218	6396
Annual Load Factor (%)	51.2	49.3	50.0
% Change Customers (yr-end)	+.9	+.5	+.4
Fixed Charge Cov. (%)	221	248	296

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	.5%	-.5%
"Cash Flow"	--	3.0%	.5%
Earnings	-2.5%	.5%	6.0%
Dividends	4.5%	3.0%	1.5%
Book Value	2.5%	.5%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	709.8	898.0	1072.9	686.4	3367.1
2009	625.9	836.0	1142.2	693.0	3297.1
2010	620.3	820.6	1139.1	683.6	3263.6
2011	659.6	799.8	**1100**	**690.6**	**3250**
2012	**675**	**850**	**1250**	**725**	**3500**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	d.04	1.13	1.50	d.48	2.12
2009	d.36	.74	2.07	d.19	2.26
2010	.07	.83	2.08	.06	3.08
2011	d.14	.78	**2.06**	**.05**	**2.75**
2012	**Nil**	**.95**	**2.25**	**.05**	**3.25**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.525	.525	.525	.525	2.10
2008	.525	.525	.525	.525	2.10
2009	.525	.525	.525	.525	2.10
2010	.525	.525	.525	.525	2.10
2011	.525	.525	.525		

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in 11 of 15 Arizona counties. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 47%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 37%; nuclear, 27%; gas, 12%; purchased, 24%. Fuel costs: 36% of revenues. Has 7,200 employees. '09 reported depreciation rate: 3.1%. Chairman, President & Chief Executive Officer: Donald E. Brandt. Incorporated: Arizona. Address: 400 North Fifth Street, Post Office Box 53999, Phoenix, Arizona 85072-3999. Telephone: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary has a general rate case pending. Arizona Public Service filed for a tariff hike of $194.1 million (6.6%), based on a return of 11% on a common-equity ratio of 53.9%. APS is asking for a regulatory mechanism that decouples electric volume and revenues, and a tracker that raises rates annually to recover infrastructure additions for generating assets and environmental compliance. The utility also wants to revise the fuel adjustment clause so that it accounts for all changes in fuel costs, not just 90% of them. (Other utilities in the state have 100% pass-through of fuel costs.) New tariffs won't take effect until mid-2012, at the earliest. Settlement talks will begin in the next several weeks.

Milder-than-normal weather conditions have prompted us to cut our 2011 earnings estimate. We reduced our estimate by $0.30 a share, to $2.75. That's at the low end of the company's guidance of $2.75-$2.90 a share. We continue to forecast share net of $3.25 in 2012, assuming APS receives a decent rate order and weather patterns return to normal.

The utility is awaiting regulatory approval for an asset acquisition. APS has agreed to pay $294 million for Southern California Edison's 739-megawatt stake in units 4 and 5 of the Four Corners coal-fired plant. The company would finance the purchase with a mix of debt and equity. APS would have to spend $300 million on environmental upgrades, but would be able to avoid more than $600 million needed for units 1, 2, and 3, which would be shut down. The transaction is expected to close in late 2012. Our figures will not reflect the deal until after it has been completed.

APS is adding solar capacity. In the first phase, it plans to build 100 mw at a cost of up to $500 million. APS has procured 83 mw, so far, at a cost of $384 million. The utility is proposing to add 100 mw more for up to $475 million.

This stock's yield isn't high enough to compensate investors for low dividend growth potential. Not only is the share price within our 3- to 5-year Target Price Range, it remains closer to the high end than the low end. Thus, total return potential over that time frame is modest.

Paul E. Debbas, CFA *November 4, 2011*

(A) Diluted egs. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 1¢. '08 EPS don't add due to rounding, '10 due to change in shares. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '10: $11.28/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '10: 11%; earned on avg. com. eq., '10: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	65

ZACKS INVESTMENT RESEARCH
Proven Ratings, Research & Recommendations
Zacks.com Quotes and Research

PINNACLE WEST CAP CORP (NYSE)

ZACKS RANK: 2 - BUY

PNW 46.32 ▲0.07 (0.15%) Vol. 490,177 16:01 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

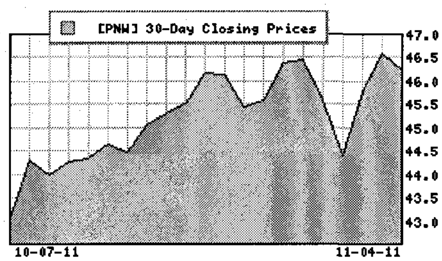
PINNACLE WEST
400 NORTH FIFTH STREET
PHOENIX, AZ 85004
Phone: 6022501000
Fax: 602-250-2430
Web: http://www.pinnaclewest.com
Email: rhickman@pinnaclewest.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/17/2012

Price and Volume Information

Zacks Rank	2
Yesterday's Close	46.25
52 Week High	47.36
52 Week Low	37.28
Beta	0.55
20 Day Moving Average	1,239,555.88
Target Price Consensus	46



% Price Change		% Price Change Relative to S&P 500	
4 Week	7.41	4 Week	-0.97
12 Week	12.72	12 Week	6.03
YTD	11.58	YTD	11.97

Share Information		Dividend Information	
Shares Outstanding (millions)	109.11	Dividend Yield	4.54%
		Annual Dividend	$2.10
Market Capitalization (millions)	5,046.38	Payout Ratio	0.69
Short Ratio	2.03	Change in Payout Ratio	-0.12
Last Split Date	N/A	Last Dividend Payout / Amount	10/28/2011 / $0.52

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.04	Current (1=Strong Buy, 5=Strong Sell)	2.73
Current Year EPS Consensus Estimate	2.88	30 Days Ago	2.73
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.75
Next EPS Report Date	02/17/2012	90 Days Ago	2.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.08	vs. Previous Year	7.69%	vs. Previous Year	-1.25%
Trailing 12 Months:	15.21	vs. Previous Quarter	187.18%	vs. Previous Quarter:	40.64%
PEG Ratio	3.02				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.26	09/30/11	8.80	09/30/11	2.66

Price/Cash Flow	7.31	06/30/11	8.40	06/30/11	2.55
Price / Sales	1.54	03/31/11	8.57	03/31/11	2.60
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.89	09/30/11	0.76	09/30/11	10.25
06/30/11	0.57	06/30/11	0.45	06/30/11	9.62
03/31/11	0.57	03/31/11	0.46	03/31/11	9.68
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	16.14	09/30/11	16.14	09/30/11	36.69
06/30/11	15.07	06/30/11	15.07	06/30/11	34.08
03/31/11	14.99	03/31/11	14.99	03/31/11	34.28
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.27	09/30/11	0.76	09/30/11	43.22
06/30/11	9.77	06/30/11	0.74	06/30/11	42.64
03/31/11	10.07	03/31/11	0.76	03/31/11	43.28

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224
TABLE OF CONTENTS TO SCHEDULES WAR

ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	3,382,856	-	3,382,856	46.06%	6.26%	2.88%
3	COMMON EQUITY	3,961,248	-	3,961,248	53.94%	10.00%	5.39%
4	TOTAL CAPITALIZATION	$ 7,344,104	$ -	$ 7,344,104	100.00%		
5	ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL						8.27%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1
COLUMN (E): LINE 2 - SCHEDULE WAR-1, PAGE 2 LINE 17
COLUMN (E): LINE 3 - SCHEDULE WAR-1, PAGE 3 LINE 7
COLUMN (F): COLUMN (D) x COLUMN (E)

FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.		(A) CAPITALIZATION	(B) RUCO	(C) RUCO ADJUSTED	(D) CAPITAL	(E)	(F) WEIGHTED
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	3,382,856	-	3,382,856	46.06%	4.08%	1.88%
3	COMMON EQUITY	3,961,248	-	3,961,248	53.94%	7.82%	4.22%
4	TOTAL CAPITALIZATION	$ 7,344,104	$ -	$ 7,344,104	100.00%		
5	FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL						6.10%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1
COLUMN (E): LINE 2 - SCHEDULE WAR-1, PAGE 2 LINE 19
COLUMN (E): LINE 3 - SCHEDULE WAR-1, PAGE 3 LINE 9
COLUMN (F): COLUMN (D) x COLUMN (E)

COST OF DEBT

LINE NO.	DESCRIPTION	(A) MATURITY DATES	(B) BALANCE AS OF DECEMBER 31, 2008	(C) RUCO ADJUSTMENT	(D) RUCO ADJUSTED BALANCE	(E) COST	(F) INTEREST	
1	POLLUTION CONTROL BONDS - VARIABLE	2024-2038	$ 43,580	$ -	$ 43,580	0.320%	$ 139	
2	POLLUTION CONTROL BONDS - FIXED	2029-2034	522,275	-	522,275	5.701%	29,774	
3	POLLUTION CONTROL BONDS WITH SENIOR NOTES	2029	90,000	-	90,000	5.050%	4,545	
4	UNSECURED NOTES	2011	400,000	-	400,000	6.375%	25,500	
5	UNSECURED NOTES	2012	375,000	-	375,000	6.500%	24,375	
6	UNSECURED NOTES	2014	300,000	-	300,000	5.800%	17,400	
7	UNSECURED NOTES	2015	300,000	-	300,000	4.650%	13,950	
8	UNSECURED NOTES	2016	250,000	-	250,000	6.250%	15,625	
9	UNSECURED NOTES	2019	500,000	-	500,000	8.750%	43,750	
10	UNSECURED NOTES	2033	200,000	-	200,000	5.625%	11,250	
11	UNSECURED NOTES	2035	250,000	-	250,000	5.500%	13,750	
12	UNSECURED NOTES	2036	150,000	-	150,000	6.875%	10,313	
13	CAPITALIZED LEASE OBLIGATIONS	2011-2012	2,001	-	2,001	5.297%	106	
14	OTHER		-	-	-	0.000%	1,286	
15								
16	TOTALS		$ 3,382,856	$ -	$ 3,382,856		$ 211,763	
17	**COST OF LONG-TERM DEBT - ORIGINAL COST**						**6.26%**	COLUMN (F), LINE 16 / COLUMN (D), LINE 16
18	**LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT**						**2.18%**	SCHEDULE WAR-1, PAGE 4, COLUMN (D), LINE 11
19	**COST OF LONG-TERM DEBT - FAIR VALUE**						$\boxed{\textbf{4.08\%}}$	LINE 8 - LINE 9

REFERENCES:
COLUMNS (A) AND (B): COMPANY FORM 10-K FILED ON 02/18/2011, COMPANY SCHEDULE D-2, PAGE 1 OF 1
COLUMN (C): TESTIMONY WAR
COLUMN (D): COLUMN (B) - COLUMN (C)
COLUMN (E): LINES 1 THROUGH 14 / LINE 16
COLUMN (F): COMPANY FORM 10-K FILED ON 02/18/2011, SCHEDULE E-9

COST OF COMMON EQUITY ESTIMATE

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.77%	SCHEDULE WAR-2, COLUMN (C), LINE 10
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	3.83%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 10
5	CAPM - ARITHMETIC MEAN ESTIMATE	5.09%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 10
6	AVERAGE OF CAPM ESTIMATES	4.46%	(LINE 4 + LINE 5) / 2
7	**COST OF COMMON EQUITY ESTIMATE - ORIGINAL COST**	**10.00%**	TESTIMONY, WAR
8	**LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT**	**2.18%**	SCHEDULE WAR-1, PAGE 4, COLUMN (D), LINE 11
9	**COST OF COMMON EQUITY ESTIMATE - FAIR VALUE**	7.82%	LINE 8 - LINE 9

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2003	2.06%	4.01%	1.95%
2	2004	1.83%	4.27%	2.44%
3	2005	1.82%	4.29%	2.47%
4	2006	2.31%	4.80%	2.49%
5	2007	2.29%	4.64%	2.35%
6	2008	1.76%	3.67%	1.91%
7	2009	1.66%	3.26%	1.60%
8	2010	1.15%	3.22%	2.07%
9	2011	1.05%	3.36%	2.31%
10	AVERAGE	1.77%	3.95%	2.18%
11	**RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT**			**2.18%**

REFERENCES

COLUMNS (A) THRU (C), LINES 1 THRU 9: FEDERAL RESERVE BANK OF ST. LOUIS WEBSITE
COLUMN (D): COLUMN (C) - COLUMN (D)
COLUMNS (B) THRU (D), LINE 10: AVERAGE OF LINES 1 THRU 9
COLUMN (D), LINE 11: TESTIMONY - WAR

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) DIVIDEND YIELD		(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AEE	AMEREN CORP.	5.05%	+	5.75%	=	10.81%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	4.81%	+	4.72%	=	9.54%
3	CNP	CENTERPOINT ENERGY, INC.	3.93%	+	4.15%	=	8.08%
4	CNL	CLECO CORPORATION	3.18%	+	5.04%	=	8.22%
5	CMS	CMS ENERGY CORPORATION	4.21%	+	5.30%	=	9.50%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	2.51%	+	6.34%	=	8.84%
7	DTE	DTE ENERGY COMPANY	4.67%	+	3.25%	=	7.92%
8	EIX	EDISON INTERNATIONAL	3.35%	+	4.50%	=	7.85%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	4.16%	+	12.61%	=	16.76%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	5.02%	+	3.56%	=	8.58%
11	IDA	IDACORP, INC.	3.07%	+	5.35%	=	8.42%
12	TEG	INTEGRYS ENERGY GROUP, INC.	5.45%	+	3.12%	=	8.57%
13	ITC	ITC HOLDINGS CORP.	1.90%	+	12.34%	=	14.24%
14	POM	PEPCO HOLDINGS INC.	5.65%	+	2.10%	=	7.76%
15	PCG	PG&E CORPORATION	4.32%	+	5.82%	=	10.14%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.42%	+	4.21%	=	8.63%
17	PPL	PPL CORPORATION	4.88%	+	7.98%	=	12.85%
18	TE	TECO ENERGY, INC.	4.83%	+	5.27%	=	10.10%
19	WR	WESTAR ENERGY, INC.	4.80%	+	4.16%	=	8.96%
20	WEC	WISCONSIN ENERGY CORPORATION	3.28%	+	6.25%	=	9.53%
21	**AVERAGE**						**9.77%**
22							

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, 2010
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AEE	AMEREN CORP.	$ 1.54	/	$ 30.47	=	5.05%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	1.84	/	38.22	=	4.81%
3	CNP	CENTERPOINT ENERGY, INC.	0.79	/	20.11	=	3.93%
4	CNL	CLECO CORPORATION	1.12	/	35.22	=	3.18%
5	CMS	CMS ENERGY CORPORATION	0.84	/	19.98	=	4.21%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	0.96	/	38.31	=	2.51%
7	DTE	DTE ENERGY COMPANY	2.35	/	50.28	=	4.67%
8	EIX	EDISON INTERNATIONAL	1.28	/	38.23	=	3.35%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	0.83	/	19.97	=	4.16%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.24	/	24.70	=	5.02%
11	IDA	IDACORP, INC.	1.20	/	39.04	=	3.07%
12	TEG	INTEGRYS ENERGY GROUP, INC.	2.72	/	49.87	=	5.45%
13	ITC	ITC HOLDINGS CORP.	1.41	/	74.16	=	1.90%
14	POM	PEPCO HOLDINGS INC.	1.08	/	19.10	=	5.65%
15	PCG	PG&E CORPORATION	1.82	/	42.12	=	4.32%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	1.06	/	23.98	=	4.42%
17	PPL	PPL CORPORATION	1.40	/	28.71	=	4.88%
18	TE	TECO ENERGY, INC.	0.86	/	17.81	=	4.83%
19	WR	WESTAR ENERGY, INC.	1.28	/	26.65	=	4.80%
20	WEC	WISCONSIN ENERGY CORPORATION	1.04	/	31.75	=	3.28%
21	**AVERAGE**						**4.17%**

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, 2010
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AEE	AMEREN CORP.	3.00%	+	2.75%	=	5.75%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	4.60%	+	0.12%	=	4.72%
3	CNP	CENTERPOINT ENERGY, INC.	4.00%	+	0.15%	=	4.15%
4	CNL	CLECO CORPORATION	5.00%	+	0.04%	=	5.04%
5	CMS	CMS ENERGY CORPORATION	5.00%	+	0.30%	=	5.30%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	5.25%	+	1.09%	=	6.34%
7	DTE	DTE ENERGY COMPANY	3.20%	+	0.05%	=	3.25%
8	EIX	EDISON INTERNATIONAL	4.50%	+	0.00%	=	4.50%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	2.80%	+	9.81%	=	12.61%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	3.00%	+	0.56%	=	3.56%
11	IDA	IDACORP, INC.	5.25%	+	0.10%	=	5.35%
12	TEG	INTEGRYS ENERGY GROUP, INC.	3.00%	+	0.12%	=	3.12%
13	ITC	ITC HOLDINGS CORP.	10.25%	+	2.09%	=	12.34%
14	POM	PEPCO HOLDINGS INC.	2.10%	+	0.00%	=	2.10%
15	PCG	PG&E CORPORATION	5.30%	+	0.52%	=	5.82%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.20%	+	0.01%	=	4.21%
17	PPL	PPL CORPORATION	5.50%	+	2.48%	=	7.98%
18	TE	TECO ENERGY, INC.	5.10%	+	0.17%	=	5.27%
19	WR	WESTAR ENERGY, INC.	3.75%	+	0.41%	=	4.16%
20	WEC	WISCONSIN ENERGY CORPORATION	6.25%	+	0.00%	=	6.25%
21	**AVERAGE**						5.59%

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, 2010
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 4
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) SHARE GROWTH	(B) x { [((M ÷ B) + 1) ÷ 2] - 1 } =	(C) EXTERNAL GROWTH (sv)
1	AEE	AMEREN CORP.	1.40%	x { [((0.93) + 1) ÷ 2] + 1 } =	2.75%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	0.85%	x { [((1.29) + 1) ÷ 2] - 1 } =	0.12%
3	CNP	CENTERPOINT ENERGY, INC.	0.30%	x { [((2.03) + 1) ÷ 2] - 1 } =	0.15%
4	CNL	CLECO CORPORATION	0.15%	x { [((1.49) + 1) ÷ 2] - 1 } =	0.04%
5	CMS	CMS ENERGY CORPORATION	0.90%	x { [((1.66) + 1) ÷ 2] - 1 } =	0.30%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	0.55%	x { [((0.95) + 1) ÷ 2] + 1 } =	1.09%
7	DTE	DTE ENERGY COMPANY	0.40%	x { [((1.23) + 1) ÷ 2] - 1 } =	0.05%
8	EIX	EDISON INTERNATIONAL	0.01%	x { [((1.13) + 1) ÷ 2] - 1 } =	0.00%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	5.00%	x { [((0.92) + 1) ÷ 2] + 1 } =	9.81%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2.00%	x { [((1.56) + 1) ÷ 2] - 1 } =	0.56%
11	IDA	IDACORP, INC.	1.00%	x { [((1.20) + 1) ÷ 2] - 1 } =	0.10%
12	TEG	INTEGRYS ENERGY GROUP, INC.	0.75%	x { [((1.32) + 1) ÷ 2] - 1 } =	0.12%
13	ITC	ITC HOLDINGS CORP.	2.00%	x { [((3.09) + 1) ÷ 2] - 1 } =	2.09%
14	POM	PEPCO HOLDINGS INC.	1.75%	x { [((1.01) + 1) ÷ 2] - 1 } =	0.00%
15	PCG	PG&E CORPORATION	2.50%	x { [((1.41) + 1) ÷ 2] - 1 } =	0.52%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	0.30%	x { [((1.09) + 1) ÷ 2] - 1 } =	0.01%
17	PPL	PPL CORPORATION	10.00%	x { [((1.50) + 1) ÷ 2] - 1 } =	2.48%
18	TE	TECO ENERGY, INC.	0.50%	x { [((1.69) + 1) ÷ 2] - 1 } =	0.17%
19	WR	WESTAR ENERGY, INC.	3.50%	x { [((1.23) + 1) ÷ 2] - 1 } =	0.41%
20	WEC	WISCONSIN ENERGY CORPORATION	0.01%	x { [((1.86) + 1) ÷ 2] - 1 } =	0.00%
21	**AVERAGE**				**1.04%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (C): COLUMN (A) x COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
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	AEE	AMEREN CORP.	2006	0.1477		8.10%		1.20%	31.86	206.60	
2			2007	0.1477		9.20%		1.36%	32.41	208.30	
3			2008	0.1181		8.70%		1.03%	32.80	212.30	
4			2009	0.4460		7.80%		3.48%	33.08	237.40	
5			2010	0.4440		8.60%		3.82%	32.15	240.40	
6			GROWTH 2006 - 2010					2.18%	2.50%		3.65%
7			2011	0.3583		7.00%		2.51%		244.00	1.50%
8			2012	0.3583		7.00%		2.51%		247.00	1.36%
9			2014-16	0.3840		7.00%		2.69%	1.50%	256.00	1.27%
10											
11	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	2006	0.4755		12.00%		5.71%	23.73	396.67	
12			2007	0.4476		11.40%		5.10%	25.17	400.43	
13			2008	0.4515		11.30%		5.10%	26.33	406.07	
14			2009	0.4478		10.40%		4.66%	27.49	478.05	
15			2010	0.3423		9.10%		3.12%	28.33	480.81	
16			GROWTH 2006 - 2010					4.49%	5.00%		4.93%
17			2011	0.4159		10.50%		4.37%		485.00	0.87%
18			2012	0.4154		10.50%		4.36%		489.00	0.85%
19			2014-16	0.4400		10.50%		4.62%	4.50%	500.00	0.79%
20											
21	CNP	CENTERPOINT ENERGY, INC.	2006	0.5489		27.80%		15.26%	4.96	313.65	
22			2007	0.4188		22.00%		9.21%	5.61	322.72	
23			2008	0.4385		21.90%		9.60%	5.89	346.09	
24			2009	0.2475		14.10%		3.49%	6.74	391.75	
25			2010	0.2710		13.80%		3.74%	7.53	424.70	
26			GROWTH 2006 - 2010					8.26%	8.50%		7.87%
27			2011	0.3417		12.00%		4.10%		426.00	0.31%
28			2012	0.3333		12.00%		4.00%		427.00	0.27%
29			2014-16	0.3333		11.50%		3.83%	10.00%	430.00	0.25%
30											
31	CNL	CLECO CORPORATION	2006	0.3382		8.30%		2.81%	15.22	57.57	
32			2007	0.3182		7.80%		2.48%	16.85	59.94	
33			2008	0.4706		9.60%		4.52%	17.65	60.04	
34			2009	0.4886		9.50%		4.64%	18.50	60.26	
35			2010	0.5721		10.60%		6.06%	21.76	60.53	
36			GROWTH 2006 - 2010					3.97%	11.00%		1.26%
37			2011	0.5458		10.00%		5.46%		60.70	0.28%
38			2012	0.4917		10.00%		4.92%		60.70	0.14%
39			2014-16	0.4182		9.50%		3.97%	6.50%	60.70	0.06%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

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, 2010
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	CMS	CMS ENERGY CORPORATION	2006	NMF		6.40%		NMF	10.03	222.78	
2			2007	0.6875		7.20%		4.95%	9.46	225.15	
3			2008	0.7073		11.70%		8.28%	10.88	226.41	
4			2009	0.4624		8.50%		3.93%	11.42	227.89	
5			2010	0.5038		12.50%		6.30%	11.19	249.60	
6			GROWTH 2006 - 2010					5.86%	1.50%		2.88%
7			2011	0.4207		12.50%		5.26%		252.00	0.96%
8			2012	0.4065		12.50%		5.08%		254.00	0.88%
9			2014-16	0.3714		12.50%		4.64%	5.00%	260.00	0.82%
10											
11	CEG	CONSTELLATION ENERGY GROUP, INC.	2006	0.5984		14.80%		8.86%	25.53	180.52	
12			2007	0.5944		14.70%		8.74%	29.93	178.44	
13			2008	-2.9792		2.70%		NMF	15.98	199.13	
14			2009	0.4637		4.10%		1.90%	43.27	200.99	
15			2010	0.4037		4.10%		1.66%	39.19	199.79	
16			GROWTH 2006 - 2010					5.29%	4.50%		2.57%
17			2011	0.5826		6.00%		3.50%		201.00	0.61%
18			2012	0.5826		5.50%		3.20%		202.00	0.55%
19			2014-16	0.7143		7.50%		5.36%	6.50%	205.00	0.52%
20											
21	DTE	DTE ENERGY COMPANY	2006	0.1510		7.50%		1.13%	33.02	177.14	
22			2007	0.2030		7.70%		1.56%	35.86	163.23	
23			2008	0.2234		7.40%		1.65%	36.77	163.02	
24			2009	0.3457		8.50%		2.94%	37.96	165.40	
25			2010	0.4171		9.40%		3.92%	39.67	169.43	
26			GROWTH 2006 - 2010					2.74%	3.50%		-1.11%
27			2011	0.3556		9.00%		3.20%		169.50	0.04%
28			2012	0.3547		9.00%		3.19%		170.00	0.17%
29			2014-16	0.3647		9.00%		3.28%	3.50%	174.00	0.53%
30											
31	EIX	EDISON INTERNATIONAL	2006	0.6646		14.00%		9.30%	23.66	325.81	
32			2007	0.6446		13.00%		8.38%	25.92	325.81	
33			2008	0.6658		12.80%		8.52%	29.21	325.81	
34			2009	0.6142		10.80%		6.63%	30.20	325.81	
35			2010	0.6209		10.40%		6.46%	32.44	325.81	
36			GROWTH 2006 - 2010					7.86%	1.05%		0.00%
37			2011	0.5309		8.00%		4.25%		325.81	0.00%
38			2012	0.5321		8.50%		4.52%		325.81	0.00%
39			2014-16	0.5692		8.00%		4.55%	0.55%	325.81	0.00%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

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, 2010
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	GXP	GREAT PLAINS ENERGY INCORPORATED	2006	-0.0247		9.40%		NMF	16.70	80.35	
2			2007	0.1075		10.10%		1.09%	18.18	86.23	
3			2008	-0.4310		4.60%		NMF	21.39	119.26	
4			2009	0.1942		4.80%		0.93%	20.62	135.42	
5			2010	0.4575		7.30%		3.34%	21.26	135.71	
6			GROWTH 2006 - 2010					1.79%	7.00%		14.00%
7			2011	0.3083		5.50%		1.70%		136.00	0.21%
8			2012	0.4276		6.50%		2.78%		155.00	6.87%
9			2014-16	0.3714		7.50%		2.79%	2.00%	155.00	2.69%
10											
11	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2006	0.0677		9.90%		0.67%	13.44	81.46	
12			2007	-0.1171		7.20%		NMF	15.29	83.43	
13			2008	-0.1589		6.50%		NMF	15.35	90.52	
14			2009	-0.3626		5.80%		NMF	15.58	92.52	
15			2010	-0.0248		7.70%		NMF	15.67	94.69	
16			GROWTH 2006 - 2010					0.67%	1.00%		3.83%
17			2011	0.0462		8.00%		0.37%		96.00	1.38%
18			2012	0.1448		9.00%		1.30%		96.00	0.69%
19			2014-16	0.3500		10.50%		3.68%	2.50%	108.00	2.67%
20											
21	IDA	IDACORP, INC.	2006	0.4894		8.90%		4.36%	25.77	43.63	
22			2007	0.3548		6.80%		2.41%	26.79	45.06	
23			2008	0.4495		7.60%		3.42%	27.76	46.92	
24			2009	0.5455		8.90%		4.85%	29.17	47.90	
25			2010	0.5932		9.30%		5.52%	31.01	49.41	
26			GROWTH 2006 - 2010					4.11%	4.50%		3.16%
27			2011	0.6129		9.50%		5.82%		50.00	1.19%
28			2012	0.6066		9.00%		5.46%		50.50	1.10%
29			2014-16	0.5455		8.50%		4.64%	5.00%	51.00	0.64%
30											
31	TEG	INTEGRYS ENERGY GROUP, INC.	2006	0.3504		9.70%		3.40%	35.61	43.06	
32			2007	-0.0323		5.50%		NMF	42.58	75.99	
33			2008	-0.6962		3.90%		NMF	40.79	75.99	
34			2009	-0.1930		6.10%		NMF	37.62	75.98	
35			2010	0.1605		8.70%		1.40%	37.57	77.35	
36			GROWTH 2006 - 2010					2.40%	5.50%		15.77%
37			2011	0.1758		9.00%		1.58%		78.30	1.23%
38			2012	0.2229		9.00%		2.01%		78.30	0.61%
39			2014-16	0.3200		9.50%		3.04%	1.50%	78.30	0.24%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

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

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	ITC	ITC HOLDINGS CORP.	2006	-0.1739		6.20%		NMF	12.55	42.40	
2			2007	0.3274		13.00%		4.26%	13.12	42.92	
3			2008	0.4566		11.80%		5.39%	18.71	49.65	
4			2009	0.5155		12.90%		6.65%	20.20	50.08	
5			2010	0.5387		13.00%		7.00%	22.03	50.72	
6			GROWTH 2006 - 2010					5.82%	-		4.58%
7			2011	0.5818		13.50%		7.85%		52.00	4.58%
8			2012	0.6286		14.50%		9.11%		52.75	2.52%
9			2014-16	0.6909		15.50%		10.71%	10.50%	55.00	1.98%
10											
11	POM	PEPCO HOLDINGS INC.	2006	0.2180		7.00%		1.53%	18.82	191.93	
12			2007	0.3203		7.40%		2.37%	20.04	200.51	
13			2008	0.4404		9.50%		4.18%	19.14	218.91	
14			2009	-0.0189		5.50%		NMF	19.15	222.27	
15			2010	0.1290		6.50%		0.84%	18.79	225.08	
16			GROWTH 2006 - 2010					2.23%	1.00%		4.06%
17			2011	0.1360		6.50%		0.88%		227.00	0.85%
18			2012	0.1360		6.00%		0.82%		235.00	2.18%
19			2014-16	0.2970		7.50%		2.23%	2.00%	250.00	2.12%
20											
21	PCG	PG&E CORPORATION	2006	0.5217		12.70%		6.63%	22.44	348.14	
22			2007	0.4820		11.80%		5.69%	24.18	353.72	
23			2008	0.5155		12.60%		6.50%	25.97	361.06	
24			2009	0.4455		11.20%		4.99%	27.88	370.63	
25			2010	0.3546		9.70%		3.44%	28.55	395.23	
26			GROWTH 2006 - 2010					5.45%	10.50%		3.22%
27			2011	0.3382		9.00%		3.04%		405.00	2.47%
28			2012	0.4873		11.00%		5.36%		420.00	3.09%
29			2014-16	0.4824		11.50%		5.55%	5.50%	425.00	1.46%
30											
31	POR	PORTLAND GENERAL ELECTRIC COMPANY	2006	0.4035		5.80%		2.34%	19.58	62.50	
32			2007	0.6009		11.00%		6.61%	21.05	62.53	
33			2008	0.3022		6.40%		1.93%	21.64	62.58	
34			2009	0.2290		6.20%		1.42%	20.50	75.21	
35			2010	0.3735		7.90%		2.95%	21.14	75.32	
36			GROWTH 2006 - 2010					3.05%	2.00%		4.77%
37			2011	0.4700		9.00%		4.23%		75.50	0.24%
38			2012	0.4732		9.00%		4.26%		75.75	0.29%
39			2014-16	0.4667		9.00%		4.20%	3.50%	76.50	0.31%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
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COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

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, 2010
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	PPL	PPL CORPORATION	2006	0.5197		17.30%		8.99%	13.30	385.04	
2			2007	0.5361		18.20%		9.76%	14.88	373.27	
3			2008	0.4531		18.20%		8.25%	13.55	374.58	
4			2009	-0.1597		8.10%		NMF	14.57	377.18	
5			2010	0.3886		12.00%		4.66%	16.98	483.39	
6			GROWTH 2006 - 2010					7.91%	7.00%		5.85%
7			2011	0.4167		12.00%		5.00%		578.00	19.57%
8			2012	0.4510		12.50%		5.64%		580.00	9.54%
9			2014-16	0.4333		11.50%		4.98%	9.00%	680.00	7.06%
10											
11	TE	TECO ENERGY, INC.	2006	0.3504		14.10%		4.94%	8.25	209.50	
12			2007	0.3858		13.20%		5.09%	9.56	210.90	
13			2008	-0.0390		8.10%		NMF	9.43	212.90	
14			2009	0.2000		10.30%		2.06%	9.75	213.90	
15			2010	0.2743		11.20%		3.07%	10.10	214.90	
16			GROWTH 2006 - 2010					3.79%	5.00%		0.64%
17			2011	0.3462		12.50%		4.33%		216.00	0.51%
18			2012	0.3862		13.50%		5.21%		217.00	0.49%
19			2014-16	0.4000		13.00%		5.20%	5.00%	220.00	0.47%
20											
21	WR	WESTAR ENERGY, INC.	2006	0.4787		10.70%		5.12%	17.62	87.39	
22			2007	0.4130		9.20%		3.80%	19.14	95.46	
23			2008	0.1145		6.20%		0.71%	20.18	108.31	
24			2009	0.0625		6.30%		0.39%	20.59	109.07	
25			2010	0.3111		8.20%		2.55%	21.25	112.13	
26			GROWTH 2006 - 2010					2.51%	6.00%		6.43%
27			2011	0.2381		7.50%		1.79%		117.00	4.34%
28			2012	0.3053		8.50%		2.59%		120.00	3.45%
29			2014-16	0.4000		10.00%		4.00%	2.00%	128.00	2.68%
30											
31	WEC	WISCONSIN ENERGY CORPORATION	2006	0.6515		10.80%		7.04%	12.35	233.94	
32			2007	0.6479		10.90%		7.06%	13.25	233.89	
33			2008	0.6447		10.70%		6.90%	14.27	233.84	
34			2009	0.5750		10.60%		6.10%	15.26	233.82	
35			2010	0.5833		12.00%		7.00%	16.26	233.77	
36			GROWTH 2006 - 2010					6.82%	7.50%		-0.02%
37			2011	0.5163		13.00%		6.71%		232.00	-0.76%
38			2012	0.4933		13.00%		6.41%		228.00	-1.24%
39			2014-16	0.4000		14.00%		5.60%	4.50%	224.00	-0.85%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
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COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

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, 2010
GROWTH RATE COMPARISON

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 6

LINE	STOCK		(A)	(B) ZACKS	(C) VALUE LINE PROJECTED			(D) VALUE LINE HISTORIC			(E) VALUE LINE &	(F) 5 - YEAR COMPOUND HISTORY		
NO.	SYMBOL	COMPANY NAME	(br) + (sv)	EPS	EPS	DPS	BVPS	EPS	DPS	BVPS	ZACKS AVGS.	EPS	DPS	BVPS
1	AEE	AMEREN CORP.	5.75%	2.55%	-2.00%	-3.00%	1.50%	-1.50%	-6.00%	2.50%	-0.85%	1.02%	-11.76%	0.23%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	4.72%	3.12%	4.50%	4.00%	4.50%	2.00%	2.00%	5.00%	3.59%	-2.35%	3.33%	4.53%
3	CNP	CENTERPOINT ENERGY, INC.	4.15%	1.13%	3.00%	3.00%	10.00%	5.00%	13.50%	8.50%	6.30%	-5.29%	6.78%	11.00%
4	CNL	CLECO CORPORATION	5.04%	2.37%	6.00%	9.50%	6.50%	7.50%	0.50%	11.00%	6.20%	13.91%	2.15%	9.35%
5	CMS	CMS ENERGY CORPORATION	5.30%	1.45%	7.00%	14.00%	5.00%	17.50%	-	1.50%	7.74%	20.07%	-	2.77%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	6.34%	2.98%	18.00%	-4.00%	6.50%	-16.00%	1.50%	4.50%	1.93%	-19.11%	-10.71%	11.31%
7	DTE	DTE ENERGY COMPANY	3.25%	3.60%	4.50%	4.00%	3.50%	2.50%	1.00%	3.50%	3.23%	11.15%	1.18%	4.69%
8	EIX	EDISON INTERNATIONAL	4.50%	2.93%	0.58%	0.54%	0.55%	1.46%	1.05%	1.05%	1.17%	0.53%	3.66%	8.21%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	12.61%	1.26%	6.00%	-	2.00%	-11.50%	-8.00%	7.00%	-0.54%	-1.42%	-15.91%	6.22%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	3.56%	1.40%	11.00%	1.00%	2.50%	-6.00%	-	1.00%	1.82%	-2.34%	0.00%	3.91%
11	IDA	IDACORP, INC.	5.35%	3.40%	4.00%	4.00%	5.00%	11.00%	-2.50%	4.50%	4.20%	5.85%	0.00%	4.74%
12	TEG	INTEGRYS ENERGY GROUP, INC.	3.12%	3.37%	9.00%	-	1.50%	-8.00%	4.00%	5.50%	2.56%	-1.98%	4.51%	1.35%
13	ITC	ITC HOLDINGS CORP.	12.34%	3.30%	14.00%	5.50%	10.50%	-	-	-	8.33%	32.55%	4.95%	15.10%
14	POM	PEPCO HOLDINGS INC.	2.10%	1.24%	2.50%	1.00%	2.00%	-5.00%	1.50%	1.00%	0.61%	-1.74%	0.95%	-0.04%
15	PCG	PG&E CORPORATION	5.82%	3.52%	6.00%	4.50%	5.50%	7.00%	-	10.50%	6.17%	0.54%	8.36%	6.21%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.21%	2.01%	7.50%	3.00%	3.50%	7.50%	-	2.00%	4.25%	9.85%	11.21%	1.93%
17	PPL	PPL CORPORATION	7.98%	2.61%	7.00%	3.50%	9.00%	1.00%	10.00%	7.00%	5.73%	0.00%	6.21%	6.30%
18	TE	TECO ENERGY, INC.	5.27%	1.31%	10.50%	4.50%	5.00%	12.00%	-0.50%	5.00%	5.40%	-0.87%	1.92%	5.19%
19	WR	WESTAR ENERGY, INC.	4.16%	1.77%	8.50%	3.00%	2.00%	1.00%	7.00%	6.00%	4.18%	-1.08%	6.06%	4.79%
20	WEC	WISCONSIN ENERGY CORPORATION	6.25%	2.15%	8.50%	16.00%	4.50%	8.50%	10.00%	7.50%	8.16%	9.82%	14.84%	7.12%
21					6.80%	4.11%	4.55%	1.89%	2.34%	4.98%		3.46%	1.99%	5.75%
22	AVERAGES		5.59%	2.37%		5.16%			3.07%		4.01%		3.73%	

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 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THROUGH 20
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 08/26/2011, 09/23/2011 AND 11/04/2011

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	AEE	AMEREN CORP.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)] =	4.57%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	k	=	0.97%	+ [	0.70	x (	9.90%	-	5.40%	)] =	4.12%
3	CNP	CENTERPOINT ENERGY, INC.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)] =	4.57%
4	CNL	CLECO CORPORATION	k	=	0.97%	+ [	0.65	x (	9.90%	-	5.40%	)] =	3.89%
5	CMS	CMS ENERGY CORPORATION	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)] =	4.34%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)] =	4.57%
7	DTE	DTE ENERGY COMPANY	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)] =	4.34%
8	EIX	EDISON INTERNATIONAL	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)] =	4.57%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)] =	4.34%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	k	=	0.97%	+ [	0.70	x (	9.90%	-	5.40%	)] =	4.12%
11	IDA	IDACORP, INC.	k	=	0.97%	+ [	0.70	x (	9.90%	-	5.40%	)] =	4.12%
12	TEG	INTEGRYS ENERGY GROUP, INC.	k	=	0.97%	+ [	0.90	x (	9.90%	-	5.40%	)] =	5.02%
13	ITC	ITC HOLDINGS CORP.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)] =	4.57%
14	POM	PEPCO HOLDINGS INC.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)] =	4.57%
15	PCG	PG&E CORPORATION	k	=	0.97%	+ [	0.55	x (	9.90%	-	5.40%	)] =	3.44%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)] =	4.34%
17	PPL	PPL CORPORATION	k	=	0.97%	+ [	0.65	x (	9.90%	-	5.40%	)] =	3.89%
18	TE	TECO ENERGY, INC.	k	=	0.97%	+ [	0.85	x (	9.90%	-	5.40%	)] =	4.79%
19	WR	WESTAR ENERGY, INC.	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)] =	4.34%
20	WEC	WISCONSIN ENERGY CORPORATION	k	=	0.97%	+ [	0.65	x (	9.90%	-	5.40%	)] =	3.89%
21	**AVERAGE**						0.75						4.32%

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)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 09/23/2011 THROUGH 11/11/2011 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2010 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2011 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) k	=	r_f	+ [	ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AEE	AMEREN CORP.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	k	=	0.97%	+ [	0.70	x (	11.90%	-	5.50%	)]	=	5.45%
3	CNP	CENTERPOINT ENERGY, INC.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
4	CNL	CLECO CORPORATION	k	=	0.97%	+ [	0.65	x (	11.90%	-	5.50%	)]	=	5.13%
5	CMS	CMS ENERGY CORPORATION	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
7	DTE	DTE ENERGY COMPANY	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
8	EIX	EDISON INTERNATIONAL	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	k	=	0.97%	+ [	0.70	x (	11.90%	-	5.50%	)]	=	5.45%
11	IDA	IDACORP, INC.	k	=	0.97%	+ [	0.70	x (	11.90%	-	5.50%	)]	=	5.45%
12	TEG	INTEGRYS ENERGY GROUP, INC.	k	=	0.97%	+ [	0.90	x (	11.90%	-	5.50%	)]	=	6.73%
13	ITC	ITC HOLDINGS CORP.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
14	POM	PEPCO HOLDINGS INC.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
15	PCG	PG&E CORPORATION	k	=	0.97%	+ [	0.55	x (	11.90%	-	5.50%	)]	=	4.49%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
17	PPL	PPL CORPORATION	k	=	0.97%	+ [	0.65	x (	11.90%	-	5.50%	)]	=	5.13%
18	TE	TECO ENERGY, INC.	k	=	0.97%	+ [	0.85	x (	11.90%	-	5.50%	)]	=	6.41%
19	WR	WESTAR ENERGY, INC.	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
20	WEC	WISCONSIN ENERGY CORPORATION	k	=	0.97%	+ [	0.65	x (	11.90%	-	5.50%	)]	=	5.13%
21	**AVERAGE**						0.75							5.74%

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)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 09/23/2011 THROUGH 11/11/2011 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2010 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2011 YEARBOOK.

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 8

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%	2.90%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.84%	-6.80%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	2009	-0.36%	5.00%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	2010	1.64%	2.80%	3.25%	0.72%	0.00% - 0.25%	0.13%	4.25%	5.50%	5.98%
22	CURRENT	3.90%	2.50%	3.25%	0.75%	0.00% - 0.25%	0.01%	3.22%	4.12%	4.76%

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 11/11/2011
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 11/11/2011
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

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
CAPITAL STRUCTURES OF SAMPLE COMPANIES (000's)

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 9

LINE NO.		AEE	PCT.	AEP	PCT.	CNP	PCT.	CNL	PCT.	CMS	PCT.
1	DEBT	$ 3,949.0	48.7%	$ 15,502.0	53.2%	$ 9,119.0	77.6%	$ 1,399.7	51.5%	$ 6,448.0	69.4%
3	PREFERRED STOCK	80.0	1.0%	0.0	0.0%	0.0	0.0%	1.0	0.0%	0.0	0.0%
5	COMMON EQUITY	4,073.0	50.3%	13,622.0	46.8%	2,639.0	22.4%	1,317.2	48.5%	2,837.0	30.6%
7	TOTALS	$ 8,102.0	100%	$ 29,124.0	100%	$ 11,758.0	100%	$ 2,717.9	100%	$ 9,285.0	100%
10		CEG	PCT.	DTE	PCT.	EIX	PCT.	GXP	PCT.	HE	PCT.
12	DEBT	$ 4,054.2	33.3%	$ 4,046.0	50.2%	$ 12,371.0	51.8%	$ 2,942.7	50.5%	$ 1,364.9	47.3%
14	PREFERRED STOCK	190.0	1.6%	0.0	0.0%	907.0	3.8%	0.0	0.0%	34.3	1.2%
16	COMMON EQUITY	7,918.0	65.1%	4,009.0	49.8%	10,583.0	44.4%	2,885.9	49.5%	1,483.6	51.5%
18	TOTALS	$ 12,162.2	100%	$ 8,055.0	100%	$ 23,861.0	100%	$ 5,828.6	100%	$ 2,882.9	100%
21		IDA	PCT.	TEG	PCT.	ITC	PCT.	POM	PCT.	PCG	PCT.
23	DEBT	$ 1,488.3	49.2%	$ 2,161.6	42.2%	$ 2,496.9	69.1%	$ 3,629.0	46.2%	$ 10,906.0	49.2%
25	PREFERRED STOCK	0.0	0.0%	51.1	1.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
27	COMMON EQUITY	1,536.0	50.8%	2,905.8	56.8%	1,117.4	30.9%	4,230.0	53.8%	11,282.0	50.8%
29	TOTALS	$ 3,024.3	100%	$ 5,118.5	100%	$ 3,614.3	100%	$ 7,859.0	100%	$ 22,188.0	100%
32		POR	PCT.	PPL	PCT.	TE	PCT.	WR	PCT.	WEC	PCT.
34	DEBT	$ 1,798.0	52.9%	$ 12,161.0	58.9%	$ 4,271.7	66.3%	$ 2,490.9	50.8%	$ 3,932.0	50.6%
36	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	30.4	0.4%
38	COMMON EQUITY	1,599.0	47.1%	8,478.0	41.1%	2,170.6	33.7%	2,410.4	49.2%	3,802.1	49.0%
40	TOTALS	$ 3,397.0	100%	$ 20,639.0	100%	$ 6,442.3	100%	$ 4,901.2	100%	$ 7,764.5	100%

LINE NO.		ELECTRIC COMPANY SAMPLE AVERAGE	PCT.
45	DEBT	$ 106,531.9	53.6%
47	PREFERRED STOCK	1,294	0.7%
49	COMMON EQUITY	90,899	45.7%
51	TOTALS	$ 198,724.7	100%

REFERENCE:
MOST RECENT SEC 10(k) FILINGS OR COMPANY ANNUAL REPORTS

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF

FRANK W. RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 18, 2011

TABLE OF CONTENTS

INTRODUCTION

Q. MR. RADIGAN, WOULD YOU PLEASE STATE YOUR FULL NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding utility industries and specializing in the fields of rates, planning and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203. A summary of my education, my business experience and my qualification is attached as Exhibit-FWR-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO"). RUCO was established by the Arizona Legislature in 1983 to represent the interests of residential utility ratepayers in rate-related proceedings involving public service corporations before the Arizona Corporation Commission ("ACC" or "Commission").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked to review the reasonableness of the Arizona Public Service Company's ("APS" or the "Company") rate request filed on June 1, 2011 and present RUCO's recommended revenue requirement in this proceeding. Based on my adjustment together with the recommendations of RUCO witness William Rigsby RUCO proposes that no net change in rates be made at this time.[1]

Q WHAT IS RUCO'S PHILOSOPHY GOING INTO THIS RATE CASE?

A. RUCO was a signatory to the 2009 Settlement Agreement. At that time, RUCO's chief concern was to end the cycle of financial "emergencies" associated with the Company's corporate health. RUCO realized that it was not in the ratepayers' interest to have a utility continuously on the verge of falling below investment grade rating. The last few rate cases had provided just enough rate relief to keep its rating from falling to junk status, but never enough to achieve real financial health. RUCO believes the 2009 Settlement Agreement put APS on the path to financial health which resulted in ratepayer benefits such as the ability for the utility to acquire debt at lower rates.

The 2009 Settlement Agreement "jump started" APS's progress on this path to financial health. That said, one must also recognize that in these tough economic times one must also expect the Company to pare expenditures at every opportunity. It cannot be just a desire that utility companies tighten their belts at the same time that their customers are tightening, and sometimes retightening, theirs. As such, one needs to bring balance to the issue and that is what RUCO advocates.

[1] This is done through a combination an increase in bases rates with an equal offsets of credits available through Power Supply Adjustor.

RUCO's position in this rate case is to continue the momentum of the Settlement with a resolution of this rate case that culminates in continued strong financial metrics without unjustly enriching the utility at the expense of ratepayers. RUCO also supports the continued investment in renewable technologies and would allow for the inclusion of post-test year plant for this category. Our rate proposal is to increase base rates for infrastructure investment made up to the end of the test year and offset set the cost of supporting these investments with credits available through lower fuel costs available from the Power Supply Adjustor. This approach provides fairness and balance to stockholders and ratepayers. Stockholders receive the revenues necessary to pay for investments already made and ratepayers do not pay for investment made after the test year which gives the utility the incentive to invest wisely.

SUMMARY

Q. COULD YOU PLEASE SUMMARIZE THE FINDINGS OF YOUR REVIEW?

A. Yes. Company witness Jason LeBenz provided the standard filing requirement schedules and made a total of thirty-five adjustments to normalize the 2010 test year income statement. These adjustments included a series of normalization of 2010 revenues and expenses, adjustments to annualize latest knows costs to reflect such things as staffing levels and union contract rates and to make adjustments for out of period costs/revenue elements or other cost/revenues that are not expected to reoccur. A review of the presentation shows that the two most notable features of the rate request are a request for a return on equity of 11% and a request to be allowed to charge for 18 months of post-test year plant additions in amount of approximately $690 million. These two items account for approximately $150 million of the $194 million non-fuel base rate increase. In short they drive the whole case.

The focus of allocating risk between company and ratepayers plays on several proposals made by the Company in this case. The Company has much ability to control costs as compared to ratepayers and should bear the risk of minimizing them. With this in mind, my recommendations are reflected in RUCO's cost of service exhibits which are appended as Exhibit--FWR-2 and reflect the following recommendations:

1. A net rate decrease of $0 million.
2. No post-year year plant additions for fossil, nuclear or distribution plant.
3. Allow recovery of test year AZ Sun costs and 18 months of post test year AZ Sun costs.
4. Continuation of the Power Supply adjustment ("PSA") with 90/10 sharing.
5. Reject the proposal to include chemical costs in the PSA.
6. Reject the proposal to establish an Environmental and Reliability Account.
7. Rejection of coal mine reclamation cost adjustment which would allow a four year recovery of costs.
8. Rejection at this time of Company's low income adjustment.

9. The Company's Decoupling Mechanism (the Energy and Infrastructure Account) is a rate design issue and will be addressed in the RUCO testimony to be filed on December 2, 2011.

The implementation of these recommendations result in a base rate increase of $140 million (a $98 million increase in base rate to covers costs and a $42 million from the transfer of the Az Sun program funding from the RES to base rates) offset by a credit of $140 million from the PSA. I would note that the PSA does have a credit of $153 million so the $140 million transfer still leaves another $13 million credit in the PSA which can be used to offset future rate increases. A summary of the details of the rate change of the Company and RUCO is presented in the table below.

Rate Element	APS Position - 10/27 ($Millions)	RUCO Position ($Millions)
Base Rates	$196	$98
Az Sun transfer to base rates	$42	$42
Base Fuel Change	($153)	($140)
Net Rate Change	$85	$0

Q. PLEASE CONTINUE

A. The Company's presentation in this case is essentially a continuation of the Settlement in the last Arizona Public Service ("APS") rate case, Docket No. E-

01345A-08-0172, which was approved by the Commission in Decision No 71448 (the "Settlement"). As testified to by Company Witness Guldner the Company views this proceeding as critical in maintaining the financial and regulatory momentum established in the Settlement (Guldner direct at page 1, lines 22-25). As described by Mr. Guldner the Settlement marked a turning point in providing for the electric infrastructure needed for Arizona's future while allowing APS the financial strength and stability to attract capital (Id at page 2). This was done by providing significant cash relief and other mechanisms (Id). The Company's presentation seeks to reset base rates at a level which is described as a moderate increase and reset many of the cost recovery mechanisms currently in place and establish a series of other automatic adjustment clauses which it describes as improving its financial health while also meeting regulatory objectives (e.g. rate decoupling so that energy conservation programs can succeed). In fact, the Company's whole case is based on non-traditional ratemaking proposals – post-test year plant recovery, automatic adjustors and decoupling.

The Settlement was a comprehensive resolution of numerous and divergent issues in 2009 that set the stage for long term financial health of the Company while at the same time achieving some energy efficiency goals and commitments to renewable energy goals. One provision that does carry forward is the commitment to process rate cases within 12 months. This is a provision that will benefit the Company for the long term and the value of this one provision is evidenced by the Company's own presentation.

> "APS's financial pressure is not caused by too much debt, operational inefficiency, or poor cost management. Rather, the primary cause of APS's substandard financial performance is the rate making process in Arizona has been lengthy (often taking, for APS as much as 18-24 months to resolve) and is based on a historical test year – conditions resulting in persistent regulatory lag. Under such a regulatory model, the rates set in APS rate cases have historically been based on costs as much as three to five years old." (Hatfield direct at page 4)

With the commitment by the Commission to streamline the rate review process the primary cause of the Company's past substandard financial performance is now history. With that gone one does not need to adopt the non-traditional ratemaking techniques used in the Settlement. One of those non-traditional provisions of the Settlement is the one for providing for a return on post-tear year plant additions. This provision was unique to that case as it addressed the Company's financial health and the fact that it took almost two years to adjudicate the case. The normal regulatory framework in Arizona is to set rates on a historical test year basis and provide for a return on equity higher than that usually set for utilities that use a pro-forma test year. While this regulatory framework may result in regulatory lag on the recovery of return on investment it also provides the Company an incentive to be frugal in investment decisions and adequately rewards stockholders for the added risk. Central to the RUCO presentation therefore is strict adoption of no pro-forma adjustments and providing for a higher return on equity. This focus will continue to provide the Company the ability to strengthen its financial metrics while at the same time keeping rates at reasonable levels.

<u>REVIEW OF RATE REQUEST</u>

Q. PLEASE DISCUSS THE COMPANY'S FILING

A. On June 1, 2011, APS filed a rate case using adjusted Test Year sales and expenses for the Company's jurisdictional electric operations for the twelve months ended December 31, 2010 ("Test Year"). The rate request was to increase base rates by a net $95 million. The net $95 million was comprised of three parts a need for a non-fuel increase in base rates of $194 million, a transfer of $45 million of revenues to support the Az Sun Program from the Renewable Energy Surcharge ("ERS") to base rates and a decrease in base fuel expense of $144 million[2].

In addition to the base rate change in its presentation the Company also made a series of proposals for new riders, adjustment mechanisms, modifications to existing mechanisms including a decoupling mechanism, an adjustment to reflect increase in generation plant balances, removal of cost sharing on the power supply adjustor, and a mechanism to recover costs for efficiency programs. Through a variety of witnesses the case has been largely summarized by the Company as a continuation of the Company's last rate case which was widely viewed as a milestone that set the stage for positive developments in Arizona energy policy (Robinson direct at page 4). According to the Company the rate

[2] On October 27, 2011 the Company updated its filing and reduced its rate request to $85 million with the non-fuel base rate increase being revised to $196 million, the Az Sun Program revised to $42 million and the base fuel expense being reduced by $153 million.

request seeks to continue the momentum set in the last rate case and take further steps to make Arizona's energy landscape sustainable for the long term (Id).

Q. PLEASE DISCUSS RUCO'S REVIEW OF THE COST OF CAPITAL.

A. Mr. William Rigsby presents the RUCO recommendations on the weighted average cost of capital, the return on equity and the recommended rate treatment to reflect fair value rate of return. Mr. Rigsby recommends a slightly lower cost of long term debt and a return on equity of 10% for plant at original cost and a Fair Value Rate of Return of 6.1%. This compares to the company's request of a 11% return on equity and a Fair Value Rate of Return of 6.47%. These recommendations lower the overall average rate of return from the Company's proposed 8.87% to 8.27%. If no other change were made this recommendation would decrease the updated rate request from $85 million to a rate increase of $40 million or $45 million.

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED POST TEST YEAR ADJUSTMENTS?

A. As noted above the company proposes to adjust for 18 months of post test year operation and maintenance expenses as well as post test year plant additions for nuclear power, fossil generation, distribution and general plant additions[3]. The operating expenses related to this proposal decrease net income by approximately

[3] The Company also proposes to transfer expenditures related to the Az Solar Program from the RES to base rates. RUCO agrees with this proposal as it merely transfers the revenue collection mechanism from the RES to base rates.

$15.3 million and increase rate base by $141 million. Together they increase the revenue requirement in this case by approximately $35 million.

The Commission has consistently ruled that post test year plant additions are generally not allowed unless extraordinary circumstances are shown to exist.[4] Every piece of evidence in this case has shown that the Company's financial health has improved. For example S&P upgraded the Company's credit rating in 2010 after the last rate case. As to necessary capital improvements I make the distinction between those necessary to serve new customers and forecast capital programs. In this case the Company has only identified $140 million of the $690 million as projects related to new customers coming on the system. The rest are upgrades to the existing equipment and can for the most part considered discretionary.

The 2009 Settlement Agreement included 18 months of post test year plant. However, that was a negotiated concession as a result of much give and take. Here, the Company requests the same amount of post test year plant without any acquiescence in other areas.

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[4] See Decisions 7001 and 7360.

Q. DOES RUCO SUPPORT INCLUSION OF ANY POST TEST YEAR PLANT?

A. Yes. RUCO supports inclusion of 18 months of post test year plant for the Company's AZ Sun program. While acceptance of such plant outside of a test year is unprecedented for RUCO, RUCO does so because it recognizes the commitment the Arizona Corporation Commission and other branches of Arizona state government have made to encourage the expansion of solar and other renewable energy generation.

<u>FOUR CORNERS COAL RECLAMATION COSTS</u>

Q. COULD YOU PLEASE DISCUSS THE APS PRO-FORMA ADJUSTMENT FOR THE COAL RECLAMATION COSTS AT THE FOUR CORNERS POWER PLANT?

A. Yes, per the contract with its coal supplier the Company must pay for the reclamation of the coal mine and environs at the time that the mine for this mine mouth power plant is retired (See response to 25.15 attached as Exhibit FWR-3). Reclamation is necessary as mining disturbs land and leaves waste material. Modern mines reclaim the surface after mining is completed and return the land to useful purposes. Currently the date for the closure of Units 1-3 at Four Corners is estimated to be July 6, 2016 when the current coal contract expires (Id). In order to recover the portion of the latest coal reclamation cost estimate by the time the units retire related to Units 1-3, the Company has amortized the cost over four years (Id). The Company's use of the latest coal reclamation cost estimate and the short life for Units 1-4 cause an increase in costs from the test year amount of $1.3 million to $7.5 million for a decrease in pro-forma operating income of $6.2 million (See APS JCL-WP32 IS Pro forma Annualize Four Corners Coal Reclamation Costs attached as Exhibit FWR-4).

Q. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. First, it is not certain that Units 1-3 will be shut down at this time. In October 2010 the EPA wanted to have the Company install selective catalytic reduction equipment on all five units at Four Corners and in February 2011 EPA changed its mind and wanted to close Units 1-3 and install Best Available Control Technology on Units 4-5 (see EPA Proposed Actions attached as Exhibit FWR-4). Obviously the EPA does not have a final plan as of yet. The Company is equally two faced. For depreciation and coal reclamation purposes the Company is planning a retirement data of 2016. Yet, the capital planning the Company is proposes to add $13.1 million of capital projects at Units 1-3 in its Post-Test Year Plant Addition adjustment presented by Company Witness Schiavoni. These projects include over $2 million in reliability upgrades to maintain the units for the long term (See Exhibit MAS-1). In addition in his testimony Mr. Schiavoni also has a picture of the new economizer being installed at Four Corners Unit 1 (See Schiavoni direct at page 9). An economizer which is a central part of a generating plant would not be knowingly upgraded on a Unit that is only going to provide only four more years of service. With all of these facts it is not a certainty that Units 1-3 will be retired in 2016. As such, at least for coal reclamation purposes the pro-forma adjustment should be rejected and replaced with one that reflects just the updated cost reclamation estimate. This results in a recovery of the reclamation costs over a longer period, 26 years, which is the projected service life of Four Corners Units 4 and 5 and is exactly the methodology that the Company depreciation expert proposed for recovery the unrecovered book reserve for Units 1-3 (See White direct at page 10). This proposal increases pro-forma net income by $1.6 million.

LOW INCOME CUSTOMER DISCOUNT

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED PRO-FORMA ADJUSTMENT FOR THE LOW INCOME CUSTOMER DISCOUNT?

A. APS is proposing to adjust test year revenues to reflect the growth in low income programs from the end of the test year to mid-year 2012, when new rates are projected to be implemented (See Meissner direct at page 37). Low Income programs offer a lower base rate and a bill discount program. The Company reports that the programs resulted in test year base revenues being lower by approximately $20 million dollars (Id). For the rate case the Company proposes that it be allowed to reflect a growth in losses resulting from the low income program (Id). The Company notes that between January 2010 and December 2010 the number of customers participating in low income programs grew from 58,885 to 66,738 for an annual growth rate of 13.3% (Id). The Company projects this growth to continue at this annual growth rates and proposes an adjustment to test year revenues for low income programs is a reduction of $4.2 million (Id). APS believes that this adjustment to test year revenues is reasonable and appropriate since the amounts are known and measureable and occur in direct proximity to the test year (Meissner direct at page 38).

Q. DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT?

A. No. The Company's justification for this adjustment is one data point the growth between January 2010 and January 2011. This is not indicative of any trend let alone good justification of a pro-forma adjustment to rates. Besides the fact economic conditions in Arizona are improving. According to the Bureau of Labor Statistics the unemployment rate in Arizona has decreased from 9.6% in December 2010 to 9.1% in September 2011[5]. If economic conditions continue to improve there is a possibility that the number of low income customers could actually decrease. Based on the one data point presented by the Company I believe that the Company has not met its burden of proof that its proposed adjustment is actually known and actually measurable. Rejection of this proposal increase pro-forma net income by $2.6 million ($4.2 million of revenues less income taxes).

[5] http://data.bls.gov/timeseries/LASST04000003

ADJUSTOR MECHANISMS

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED ADJUSTOR MECHANISMS

A. As noted above the Company has proposed a series of adjustor mechanisms in this proceeding. Some such as the ERA are completely new and others such as proposed changes to the PSA are a modification to existing mechanisms already in place. Overall, the proposed mechanisms seek to give the Company greater protection of its bottom line, i.e. net income. For example, modifications to the PSA are designed to protect the Company from increases in the cost of chemicals and relieve the Company from sharing in fuel cost variations. Another example is the proposed ERA where the Company would be allowed to recover any investment in its generating plant.

The Arizona Court of Appeals discusses adjustment mechanisms in Scates v. Arizona Corporation Commission. The court indicated that such mechanisms are restricted to certain narrowly defined operating expenses that are characterized by fluctuations. The Commission has also defined adjustment mechanisms as applying to expenses that routinely widely fluctuate. The Commission stated the following regarding adjustor mechanisms:

> The principle justification for a fuel adjustor is volatility in fuel prices. A fuel adjustor allows the Commission to approve changes in rates for a utility in response to volatile changes in fuel or purchased power prices without having to conduct a rate case. (Arizona Public Service Company, Decision No. 56450, Page 6, dated April 13, 1989)

With the possible exception of the Company's proposed fuel and purchased power adjustor, none of the proposed mechanisms fit the criteria of a widely fluctuating volatile expense. In fact the returning customer, transition cost, and systems benefit proposed adjustors merely provide for the recovery of discrete and finite sets of expenses that can be quantified with certainty and will not be subject to cost volatility. These proposed mechanisms would more aptly be described as surcharges rather than adjustors.

The Company has repeatedly stated that its proposed adjustor mechanisms comport with and continue the spirit of the 2009 Settlement Agreement. However, RUCO points out that the Settlement was a well-debated negotiated settlement that was fair to both the utility and the ratepayers. While the Settlement did provide several benefits to the utility, it also included numerous ratepayer benefits including requiring the utility to contain its expenses. In its Application, the Company ***adds*** to the benefits it received in the Settlement such as the ERA, including chemicals in the PSA, eliminating the 90/10 sharing provision, a decoupling mechanism, but makes not additional commitments that inure to the benefit of the ratepayer.

PROPOSED MODIFICATION TO PSA

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL FOR MODIFICATION TO THE PSA.

A. Company witness Peter Ewen proposes two modifications to the PSA. The first is to remove the 90/10 sharing provision which was approved by the Commission in Decision No. 69663 (June 28, 2007) and the second is to include the cost associated with environmental chemical costs, primarily lime, in the PSA (Ewen Direct at page 13).

As to the 90/10 Sharing provision the Company proposes that the PSA be modified to allow full pass-through of all fuel and purchased power costs, instead of the current sharing provision whereby the Company is only allowed to recover can only recover from customers 90% of most fuel expenses above the amounts recovered through the Base Fuel Rate (Ewen at page 15). To support its position to change the PSA the Company has four main arguments. First, it states that it is the only Company to have a 90/10 sharing provision in Arizona (Ewen direct at page 14). Since the implementation of the sharing provision there have been audits of the Company's fuel procurement practices which showed that APS's hedging and procurement practices and deemed them to be sound (Id). In addition, the soundness of its fuel purchasing strategy was recently confirmed in a benchmarking study (Id). Third, the Company notes that through the recent adoption of the new Integrated Resource Planning Rules ("IRP"), the Commission will effectively approve the Company's proposed resource mix so presumably the

Company is acting prudently in that area (Id). Fourth, the Company argues that the only other variables that exist are fuel costs (the cost of fuel and purchased power market prices) which is something entirely outside of APS's control and power plant operations (Id). On power plant operations the Company argues these have been effectively reviewed in prudence determinations (Id).

Q. DO YOU AGREE WITH THE COMPANY'S REASONING?

A. No. Sharing provisions are established so that the utility has a financial incentive to control the cost which comprises approximately one third of the customers' bill. While the Company argues that it has no control over market prices for fuel and purchased power, customers have even less. Customers must rely on the utility to use its best efforts to keep costs at a minimum and a sharing mechanism is the best way to do that. The Company's own arguments belie its efforts in this area. The Company hedges fuel costs because they are at risk for market price increase. In the IRP process the Commission does not assume responsibility of the resource mix but is there to make sure the Company is doing lest cost planning. As to power plant operations the Company's coal and nuclear power plant run at very high availability and capacity factors. This is not done by chance but rather by the Company's efforts to keep them up and running. And this is exactly the outcome one wants as high availability of these low cost resources keeps fuel costs down. The PSA is a much better control for this type of efforts on the Company's part on a day to day basis rather than some after the fact prudence case.

Q. PLEASE DISCUSS THE INCLUSION OF ENVIRONMENTAL CHEMICAL COSTS IN THE PSA.

A. The Company is proposing to include in the PSA environmental chemical costs that directly correlate to the use of fuel. Chemicals, such as lime, ammonia, and sulfur are used to scrub the emissions from a coal plant and are dependent upon the amount of fuel burned (Ewan direct at page 15). The Company argues that as production from the power plants varies, so too does the amount of chemicals used and therefore its costs (Id). Moreover, the Company also notes that chemical costs will increase over time (Ewan direct at page 16).

While I understand the Company's viewpoint of where it would like to be relieved from worrying about cost increases for chemicals there is nothing special about these costs nor is there a showing that they are highly volatile or material to the Company's operation. The test year cost of chemicals is built into base rates and between rate cases it is a cost of doing business just like thousands of other expense items that the Company has. The Company has shown no compelling reason to include this cost in the PSA and the proposal should be rejected.

PROPOSED ERA

Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PROPSOAL FOR THE ENVIRONMENTAL AND RELIABILITY ACCOUNT?

A. Yes. As presented by Company Witness Leland Snook the Company proposes to establish an Environmental and Reliability Account ("ERA") mechanism that will allow it to recover the carrying costs of environmental improvement and generation plant capacity acquisition or additions (Snook direct at page 23). The ERA would include environmental improvement projects which are designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws or regulations (Snook at page 25). Generation plant capacity acquisitions, projects to improve efficiency or the construction of new generating plant would also be included (Id). For example, APS's pending acquisition of Southern California Edison's share of Four Corners Units 4 and 5 would be Qualified Investments for inclusion in the ERA in the year following the close of the transaction (Id). Under the Company's proposal it will calculate the ERA adjustment based on the investments that were actually placed in-service during the preceding calendar year and adjust rates on an annual basis (Snook direst at page 24). The Company believes this feature of the ERA complements its proposed post-Test Year plant adjustment proposed by APS witnesses Schiavoni, Edington and Froetscher (Snook direct at page 25).

Q. ARE THERE ANY OTHER CONSIDERATIONS THAT SHOULD BE TAKEN INTO ACOCUNT WITH RESPECT TO THIS AUTOMATIC ADJUSTOR?

A. Yes, the most practical one and that is need. One needs to remember that the utility business is one of very long term capital intensive assets. These are not costs that are highly volatile or made at a moment's notice. This is especially true for capital investments for environmental reasons or additions for capacity and/or reliability. Investments for power plant reliability or environmental compliance are easily contrasted to the utility's real short term capital needs of hooking up a new customers or replacing a street or traffic light that was demolished by a car in a rainstorm. These are low cost items easily available in inventory with construction time in hours.

Contrast the Street Light with the Economizer Replacement at the Cholla 3 Unit. This project is as $4.5 million project which is necessary to improve unit reliability due to tube failures (See Exhibit MAS 1, page 1 of 24). The economizer is a central component of any steam boiler whose purpose is to reheat condensed steam coming out of the steam turbine up to but not at the boiling pint of water. As the name implies it uses the waste heat of the steam to reheat water thereby providing improved economy to the Rankine cycle. In order to perform this project one first needs to experience the tube failures. This takes time. One then needs to analyze cause of the failures and possible solutions to the problem. This takes times. One then need to perform the economic cost of letting the problem continue versus the cost of fixing the problem. If the benefit of fixing the problem exceeds the cost, then a proposal is made to Company management to fix the problem. This takes time.

At a total cost of $4.5 million the project needs to be engineered and specifications sent out to bid. Bids must be then received and analyzed and then the most important part of all, the project must be scheduled. Project scheduling not only involves for arranging for labor and materials but also outage time of the unit itself. As I mentioned before the economizer is a central part of the steam boiler as a whole. To replace it therefore means that the unit must be shut down. Shutting down and restarting a steam boiler means shutting it down, letting it cool, draining the water out of all piping, erecting scaffolding to perform the work, performing the work, testing for leaks, demolishing scaffolding, filling the unit with water, testing again, and then finally restarting the unit. This process usually takes on the order of 5-12 weeks. One must also remember that the work must be done when the plant is down for maintenance which usually occurs doing the non-peak (i.e. not summer) period. For beginning to end this reliability project at Cholla Unit 3 could take a matter of years.

Just as with the Cholla economizer environmental projects are usually years in the making with the regulation being drafted, send out for comment, revised, compliance plans prepared and filed and then project planning can commence. In sum, I reject the notion that these types of projects are highly volatile in nature and cannot be planned with a reasonable degree of accuracy.

Q. WHAT DO YOU RECOMMEND?

A. The ERA should be rejected. According to the proposed plan of administration all any project needs to qualify is that the plant in generation, it has a work order, and it costs will exceed $500,000 (Attachment LRS-3). With this definition and the low dollar threshold I believe that almost <u>any</u> project at a generation plant would qualify for recovery. Similar to the post-test plant adjustment the

Company is seeking the Commission to approve a mechanism that will act as a formula rate whereby rates are continually adjusted upward to fund the Company's growth strategy.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

QUALIFICATIONS OF FRANK W. RADIGAN

Q. MR. RADIGAN, WOULD YOU PLEASE STATE YOUR FULL NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding utility industries and specializing in the fields of rates, planning and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203

Q. WOULD YOU PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the Department of Public Service, the staff arm of the New York State Public Service Commission. I served in the Rates and System Planning sections of the Power Division and in the Rates Section of the Energy and Water Division. My responsibilities included resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the State and encompassed rate design and performing embedded and marginal cost of service studies, as well as depreciation studies.

Before leaving the Commission, I was responsible for directing all engineering staff during major proceedings, including those relating to rates, integrated resource planning and environmental impact studies. In February 1997, I left the Commission and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own company.

In my 30 years of experience, I have testified as an expert witness in utility rate proceedings on more than 100 occasions before various utility regulatory bodies, including the Arizona Corporation Commission, the Connecticut Department of Utility Control, the Delaware Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the New York State Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board and the Federal Energy Regulatory Commission.

I currently advise a variety of regulatory commissions, consumer advocates, municipal utilities and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A summary of my qualifications and experience is attached.

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998-Present **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997-1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** - Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981-1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** - Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning - Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool - the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing - Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting - El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review - Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power - Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures - Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Jurisdictional Cost of Service – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

Rate Case Cost of Service Study – Heritage Hills Water Works- For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

Rate Case Cost of Service Study - Stowe Electric Department, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Study - Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation.

Rate Case Cost of Service Study - Village of Greene, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study - Village of Bath, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study - Village of Richmondville, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate - Massena Electric Department - For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study - Village of Hamilton, NY - For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study - Pascoag Utility District - Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department - Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study - Village of Arcade, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study - Village of Philadelphia, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study - Village of Hamilton, NY - For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study - Fillmore Gas Company - For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study - Rowlands Hollow Water Works- For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates- Independent Power Producers of New York - Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates- Pascoag Utility District - Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring - Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – **Pascoag Utility District - Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002**

Clean Air Act Lawsuit - New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources - Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study - Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study - Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities, Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 – Connecticut Water Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 – Connecticut Light & Power Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel fo the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 -- UNS Gas, INC. -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 – Arizona Public Service – On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in deprecation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 – Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design and its for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association, Northeast Public Power Association and New York State ISO.

Exhibit__(FWR-2)

<u>**Exhibit Schedule List**</u>

RUCO Schedule A-1

RUCO Schedule B-1

RUCO Schedule B-2

RUCO Schedule B-3

RUCO Schedule C-1

RUCO Schedule C-2

RUCO Fair Value Increment

RUCO Working Capital Adjustment

RUCO Pro-Forma Income Tax Calculation and Interest Expense Synchronization

RUCO Schedule A-1

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Electric Original Cost	RCND	Fair Value	Line No.
1.	Adjusted Rate Base	$ 5,544,426 (a)	$ 10,555,837 (a)	$ 8,050,131	1.
2.	Adjusted Operating Income	491,057 (b)	491,057 (b)	491,057 (b)	2.
3.	Current Rate of Return	8.86%	4.65%	6.10%	3.
4.	Required Operating Income	458,524	458,524	458,524	4.
5.	Required Rate of Return	8.27% *	4.34% *	5.70% *	5.
6.	Adjusted Operating Income Deficiency	(32,533)	(32,533)	(32,533)	6.
7.	Gross Revenue Conversion Factor	1.6532 (c)	1.6532 (c)	1.6532 (c)	7.
8.	Requested Increase in Base Revenue Requirements	$ (53,784) **	$ (53,784) **	$ (53,784) **	8.
9.	Fair Value Increment			53,784 (d)	9.
10.	Requested Increase in Base Revenue Requirements			$ 0	10.
11.	Required Rate of Return with Fair Value Increment			6.10% (d)	11.

Notes:

* The Required Rate of Return for OCRB, RCND and Fair Value does not reflect the need for a return on the difference between Fair Value Rate Base and Original Cost Rate Base but is simply a mathematical derivation based upon the original cost rate of return.

** Does not include the fair value increment reflected on Line 9.

Supporting Schedules:
(a) RUCO B-1
(b) RUCO C-1, page 2 of 2
(c) RUCO C-3
(d) RUCO Fair Value Increment

Recap Schedules:
N/A

RUCO Schedule B-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year (a) (A)	Pro Forma (a) (B)	Adjusted Test Year (a) (C)	Unadjusted Test Year (a) (D)	Pro Forma (a) (E)	Adjusted Test Year (a) (F)	Line No.
1.	Gross utility plant in service	$ 13,656,105	$ 246,932	$ 13,903,037	$ 11,522,113	$ 238,536	$ 11,760,649	1.
2.	Less: Accumulated depreciation & amortization	5,219,000	1,958	5,220,958	4,528,867	1,892	4,530,759	2.
3.	Net utility plant in service	8,437,105	244,974	8,682,079	6,993,246	236,644	7,229,890	3.
	Deductions:							
4.	Deferred income taxes	1,931,063	1,862	1,932,925	1,567,902	1,799	1,569,701	4.
5.	Investment tax credits	907	-	907	876	-	876	5.
6.	Customer advances for construction (c)	121,645	-	121,645	121,645	-	121,645	6.
7.	Customer deposits	68,084	-	68,084	68,084	-	68,084	7.
8.	Pension and other postretirement liabilities	711,164	-	711,164	661,518	-	661,518	8.
9.	Liability for asset retirements (c)	328,571	-	328,571	320,592	-	320,592	9.
10.	Other deferred credits	66,842	-	66,842	64,107	-	64,107	10.
11.	Coal mine reclamation (c)	117,243	-	117,243	114,396	-	114,396	11.
12.	Unrecognized tax benefits (c)	65,363	-	65,363	53,961	-	53,961	12.
13.	Regulatory liabilities	260,687	-	260,687	253,750	-	253,750	13.
14.	Total deductions	3,671,569	1,862	3,673,431	3,226,831	1,799	3,228,630	14.
	Additions:							
15.	Regulatory assets	822,177	-	822,177	746,508	-	746,508	15.
16.	Deferred debit income tax receivable (c)	65,498	-	65,498	63,271	-	63,271	16.
17.	Other deferred debits	77,674	-	77,674	72,203	-	72,203	17.
18.	Decommissioning trust accounts (c)	469,886	-	469,886	458,476	-	458,476	18.
19.	Allowance for working capital (d)	233,778	(8,935)	224,843	212,065	(9,357)	202,708	19.
20.	Total additions	1,669,013	(8,935)	1,660,078	1,552,523	(9,357)	1,543,166	20.
21.	Total rate base	$ 6,434,549	$ 234,177	$ 6,668,726	$ 5,318,938	$ 225,488	$ 5,544,426 (e)	21.

Supporting Schedules:
(a) RUCO B-2
(b) RUCO B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) RUCO A-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		RCND						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year (b) (A)	Pro Forma (b) (B)	Adjusted Test Year (b) (C)	Unadjusted Test Year (b) (D)	Pro Forma (b) (E)	Adjusted Test Year (b) (F)	Line No.
1.	Gross utility plant in service	$ 26,378,778	$ 246,932	$ 26,625,710	$ 22,255,775	$ 238,536	$ 22,494,311	1.
2.	Less: Accumulated depreciation & amortization	9,826,977	1,958	9,828,935	8,527,851	1,892	8,529,743	2.
3.	Net utility plant in service	16,551,801	244,974	16,796,775	13,727,924	236,644	13,964,568	3.
	Deductions:							
4.	Deferred income taxes	4,057,550	1,862	4,059,412	3,294,325	1,799	3,296,124	4.
5.	Investment tax credits	907	-	907	876	-	876	5.
6.	Customer advances for construction (c)	121,645	-	121,645	121,645	-	121,645	6.
7.	Customer deposits	68,084	-	68,084	68,084	-	68,084	7.
8.	Pension and other postretirement liabilities	711,164	-	711,164	661,518	-	661,518	8.
9.	Liability for asset retirements (c)	328,571	-	328,571	320,592	-	320,592	9.
10.	Other deferred credits	66,842	-	66,842	64,107	-	64,107	10.
11.	Coal mine reclamation (c)	117,243	-	117,243	114,396	-	114,396	11.
12.	Unrecognized tax benefits (c)	65,363	-	65,363	53,961	-	53,961	12.
13.	Regulatory liabilities	260,687	-	260,687	253,750	-	253,750	13.
14.	Total deductions	5,798,056	1,862	5,799,918	4,953,254	1,799	4,955,053	14.
	Additions:							
15.	Regulatory assets	822,177	-	822,177	746,508	-	746,508	15.
16.	Deferred debit income tax receivable (c)	65,498	-	65,498	63,271	-	63,271	16.
17.	Other deferred debits	77,674	-	77,674	72,203	-	72,203	17.
18.	Decommissioning trust accounts (c)	469,886	-	469,886	458,476	-	458,476	18.
19.	Allowance for working capital (d)	233,778	(8,935)	224,843	212,065	(6,201)	205,864	19.
20.	Total additions	1,669,013	(8,935)	1,660,078	1,552,523	(6,201)	1,546,322	20.
21.	Total rate base	$ 12,422,758	$ 234,177	$ 12,656,934	$ 10,327,193	$ 228,644	$ 10,555,837 (e)	21.

Supporting Schedules:
(a) RUCO B-2
(b) RUCO B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) RUCO A-1

RUCO Schedule B-2

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(1)		(2)		(3)	
		Actual at End of Test Year 12/31/2010		West Phoenix Unit 4 Regulatory Disallowance		**Updated in Staff 6.55 (Supplemental)** Solar Generation Post-Test Year Plant Additions	
Line No.	Description	(a) Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 13,656,105	$ 11,522,113	$ (13,833)	$ (13,363)	$ 260,765	$ 251,899
2.	Less: Accumulated Depreciation & Amort.	5,219,000	4,528,867	(3,635)	(3,511)	5,593	5,403
3	Net Utility Plant in Service	8,437,105	6,993,246	(10,198)	(9,852)	255,172	246,496
4.	Less: Total Deductions	3,671,569	3,226,831	(1,469)	(1,419)	3,331	3,218
5.	Total Additions	1,669,013	1,552,523	-	-	-	-
6.	Total Rate Base	$ 6,434,549	$ 5,318,938	$ (8,729)	$ (8,433)	$ 251,841	$ 243,278
	WITNESS:			LA BENZ		GULDNER / LA BENZ	

(1) Test Year Total Deductions and Total Additions are shown on Schedule RUCO B-1.

(2) Adjustment to reduce Test Year rate base for regulatory disallowance for West Phoenix Unit 4 as required in Decisions Nos. 67744 and 69663.

(3) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for solar generation with an estimated in service date prior to 6/30/2012.

Supporting Schedules
(a) E-1

APS Update
RUCO Adjustment

Recap Schedules:
(b) RUCO B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(4) **Updated in Staff 6.55 (Supplemental)** Fossil Generation Post-Test Year Plant Additions		(5) **Updated in Staff 6.55 (Supplemental)** Nuclear Generation Post-Test Year Plant Additions		(6) **Updated in Staff 6.55 (Supplemental)** Distribution and General and Intangibles Post-Test Year Plant Additions	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	-	-
3	Net Utility Plant in Service	-	-	-	-	-	-
4.	Less: Total Deductions	-	-	-	-	-	-
5.	Total Additions	-	-	-	-	-	-
6.	Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -

WITNESS:

(4) Adjustment to Reverse inclusion of Post-Test Year Plant Additions for fossil generation

(5) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for nuclear generation estimated in service date prior to 6/30/2012.

(6) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for distribution and general and intangibles.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) RUCO B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(7) Updated to Reflect New Pro Formas Adjust Cash Working Capital for Cost of Service Pro Formas		(8) Total Original Cost Rate Base Pro Forma Adjustments		(9) Adjusted at End of Test Year 12/31/2010	
Line No.	Description	Total Co. (M)	ACC (N)	(b) Total Co. (O)	(b) ACC (P)	(b) Total Co. (Q)	(b) ACC (R)
1.	Gross Utility Plant in Service	$ -	$ -	$ 246,932	$ 238,536	$ 13,903,037	$ 11,760,649
2.	Less: Accumulated Depreciation & Amort.	-	-	1,958	1,892	5,220,958	4,530,759
3	Net Utility Plant in Service	-	-	244,974	236,644	8,682,079	7,229,890
4.	Less: Total Deductions	-	-	1,862	1,799	3,673,431	3,228,630
5.	Total Additions	(13,482)	(9,357)	(8,935)	(9,357)	1,660,078	1,543,166
6.	Total Rate Base	$ (13,482)	$ (9,357)	$ 234,177	$ 225,488	$ 6,668,726	$ 5,544,426

WITNESS: LA BENZ

(7) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study per RUCO Schedules. See RUCO Working Cap Adj - Final.xls

Supporting Schedules
(a) E-1

Recap Schedules:
(b) RUCO B-1

RUCO Schedule B-3

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(1) Actual at End of Test Year 12/31/2010 (a) Total Co.	ACC	(2) West Phoenix Unit 4 Regulatory Disallowance Total Co.	ACC	(3) Updated in Staff 6.55 (Supplemental) Solar Generation Post-Test Year Plant Additions Total Co.	ACC
		(A)	(B)	(C)	(D)	(E)	(F)
1.	Gross Utility Plant in Service	$ 26,378,778	$ 22,255,775	$ (13,833)	$ (13,363)	$ 260,765	$ 251,899
2.	Less: Accumulated Depreciation & Amort.	9,826,977	8,527,851	(3,635)	(3,511)	5,593	5,403
3	Net Utility Plant in Service	16,551,801	13,727,924	(10,198)	(9,852)	255,172	246,496
4.	Less: Total Deductions	5,798,056	4,953,254	(1,469)	(1,419)	3,331	3,218
5.	Total Additions	1,669,013	1,552,523	-	-	-	-
6.	Total Rate Base	$ 12,422,758	$ 10,327,193	$ (8,729)	$ (8,433)	$ 251,841	$ 243,278

(1) Test Year Total Deductions and Total Additions are shown on Schedule RUCO B-1.

(2) Adjustment to reduce Test Year rate base for regulatory disallowance for West Phoenix Unit 4 as required in Decisions Nos. 67744 and 69663.

(3) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for solar generation with an estimated in service date prior to 6/30/2012.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) RUCO B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(4) Updated in Staff 6.55 (Supplemental) Fossil Generation Post-Test Year Plant Additions		(5) Updated in Staff 6.55 (Supplemental) Nuclear Generation Post-Test Year Plant Additions		(6) Updated in Staff 6.55 (Supplemental) Distribution and General and Intangibles Post-Test Year Plant Additions	
		Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
		(G)	(H)	(I)	(J)	(K)	(L)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	-	-
3	Net Utility Plant in Service	-	-	-	-	-	-
4.	Less: Total Deductions	-	-	-	-	-	-
5.	Total Additions	-	-	-	-	-	-
6.	Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -

(4) Adjustment to Reverse inclusion of Post-Test Year Plant Additions for fossil generation

(5) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for nuclear generation estimated in service date prior to 6/30/2012.

(6) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for distribution and general and intangibles.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) RUCO B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(7) Updated to Reflect New Pro Formas Adjust Cash Working Capital for Cost of Service Pro Formas		(8) Total RCND Cost Rate Base Pro Forma Adjustments		(9) Adjusted at End of Test Year 12/31/2010	
		Total Co.	ACC	(b) Total Co.	(b) ACC	(b) Total Co.	(b) ACC
		(M)	(N)	(O)	(P)	(Q)	(R)
1.	Gross Utility Plant in Service	$ -	$ -	$ 246,932	$ 238,536	$ 26,625,710	$ 22,494,311
2.	Less: Accumulated Depreciation & Amort.	-	-	1,958	1,892	9,828,935	8,529,743
3	Net Utility Plant in Service	-	-	244,974	236,644	16,796,775	13,964,568
4.	Less: Total Deductions	-	-	1,862	1,799	5,799,918	4,955,053
5.	Total Additions	(8,935)	(6,201)	(8,935)	(6,201)	1,660,078	1,546,322
6.	Total Rate Base	$ (8,935)	$ (6,201)	$ 234,177	$ 228,644	$ 12,656,935	$ 10,555,837

(7) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study per RUCO Schedules. See RUCO Working Cap Adj - Final.xls

Supporting Schedules
(a) B-4

Recap Schedules:
(b) RUCO B-1

RUCO Schedule C-1

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Total Company			
Line No.	Description	Actual For The Test Year Ended 12/31/2010 (a) (A)	Proforma Adjustments (b) (B)	Test Year Results After Proforma Adjustments (c) (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,946,463	$ 10,040	$ 2,956,503	1.
2.	Revenues from Surcharges	71,530	(71,530)	-	2.
3.	Other Electric Revenues	162,814	(25,965)	136,849	3.
4.	Total	3,180,807	(87,455)	3,093,352	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,046,815	(18,292)	1,028,523	5.
6.	Operations and maintenance excluding fuel expenses	900,372	(188,348)	712,024	6.
7.	Depreciation and amortization	406,632	(22,259)	384,373	7.
8.	Income taxes	175,440	68,598	244,038	8.
9.	Other taxes	134,467	18,191	152,658	9.
10.	Total	2,663,726	(142,110)	2,521,616	10.
11.	Operating income	517,081	54,655	571,736	11.
	Other income (deductions):				
12.	Income taxes	4,975	-	4,975	12.
13.	Allowance for equity funds used during construction	22,066	-	22,066	13.
14.	Other income	8,956	-	8,956	14.
15.	Other expense	(15,859)	-	(15,859)	15.
16.	Total	20,138	-	20,138	16.
17.	Income before interest deductions	537,219	54,655	591,874	17.
	Interest deductions:				
18.	Interest on long-term debt	205,209	-	205,209	18.
19.	Interest on short-term borrowings	8,267	-	8,267	19.
20.	Debt discount, premium and expense	4,559	-	4,559	20.
21.	Allowance for borrowed funds used during construction	(16,479)	-	(16,479)	21.
22.	Total	201,556	-	201,556	22.
23.	Net income	$ 335,663	$ 54,655	$ 390,318	23.

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

Recap Schedules:
(c) RUCO A-2

ARIZONA PUBLIC SERVICE COMPANY
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	ACC Jurisdiction: Actual For The Test Year Ended 12/31/2010 (A)	Proforma Adjustments (a) (B)	Test Year Results After Proforma Adjustments (b) (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,862,997	$ 10,040	$ 2,873,037	1.
2.	Revenues from Surcharges	71,238	(83,800)	(12,562)	2.
3.	Other Electric Revenues	146,808	(25,795)	121,013	3.
4.	Total	3,081,043	(99,555)	2,981,488	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,021,577	(18,272)	1,003,305	5.
6.	Operations and maintenance excluding fuel expenses	1,000,134	(187,542)	812,592	6.
7.	Depreciation and amortization	358,023	(26,248)	331,775	7.
8.	Income taxes	150,805	62,318	213,123	8.
9.	Other taxes	114,221	15,415	129,636	9.
10.	Total	2,644,760	(154,329)	2,490,431	10.
11.	Operating income	436,283	54,774	491,057	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	436,283	54,774	491,057	17.
	Interest deductions:				
18.	Interest on long-term debt	-	-	-	18.
19.	Interest on short-term borrowings	-	-	-	19.
20.	Debt discount, premium and expense	-	-	-	20.
21.	Allowance for borrowed funds used during construction	-	-	-	21.
22.	Total	-	-	-	22.
23.	Net income	$ 436,283	$ 54,774	$ 491,057	23.

Supporting Schedules:
(a) RUCO C-2

Recap Schedules:
(b) RUCO A-1

ARIZONA PUBLIC SERVICE COMPANY
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		ACC Jurisdiction			
Line No.	Description	Actual For The Test Year Ended 12/31/2010 (A)	Proforma Adjustments (a) (B)	Test Year Results After Proforma Adjustments (b) (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,862,997	$ 10,040	$ 2,873,037	1.
2.	Revenues from Surcharges	71,238	(83,800)	(12,562)	2.
3.	Other Electric Revenues	146,808	(25,795)	121,013	3.
4.	Total	3,081,043	(99,555)	2,981,488	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,021,577	(18,272)	1,003,305	5.
6.	Operations and maintenance excluding fuel expenses	1,000,134	(187,542)	812,592	6.
7.	Depreciation and amortization	358,023	(26,248)	331,775	7.
8.	Income taxes	150,805	62,318	213,123	8.
9.	Other taxes	114,221	15,415	129,636	9.
10.	Total	2,644,760	(154,329)	2,490,431	10.
11.	Operating income	436,283	54,774	491,057	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	436,283	54,774	491,057	17.
	Interest deductions:				
18.	Interest on long-term debt	-	-	-	18.
19.	Interest on short-term borrowings	-	-	-	19.
20.	Debt discount, premium and expense	-	-	-	20.
21.	Allowance for borrowed funds used during construction	-	-	-	21.
22.	Total	-	-	-	22.
23.	Net income	$ 436,283	$ 54,774	$ 491,057	23.

Supporting Schedules:
(a) RUCO C-2

Recap Schedules:
(b) RUCO A-1

RUCO Schedule C-2

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(1)		(2)		(3)	
		Remove Bark Beetle Remediation Amortization		Remove Test Year Surcharges and Adjustors		Include West Phoenix Unit 4 Regulatory Disallowance	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	(192,761)	(192,469)	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	(192,761)	(192,469)	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	(8,201)	(8,201)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(184,560)	(184,268)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(1,918)	(1,918)	(177,253)	(176,961)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(1,918)	(1,918)	(177,253)	(176,961)	-	-
10.	Depreciation and Amortization					(329)	(318)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	(1,918)	(1,918)	(177,253)	(176,961)	(329)	(318)
15.	Operating Income Before Income Tax	1,918	1,918	(7,307)	(7,307)	329	318
16.	Interest Expense	-	-	-	-	(257)	(248)
17.	Taxable Income	1,918	1,918	(7,307)	(7,307)	586	566
18.	Current Income Tax Rate - 39.51%	758	758	(2,887)	(2,887)	232	224
19.	Operating Income (line 15 minus line 18)	$ 1,160	$ 1,160	$ (4,420)	$ (4,420)	$ 97	$ 94
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(1) Adjustment to Test Year operations to remove 6-months of deferred bark beetle costs as authorized in Decision No. 69663.

(2) Adjustment to Test Year operations to remove the Renewable Energy Standard, Competition Rules Compliance Charge, Demand Side Management, Transmission Cost Adjustor and Regulatory Assessment surcharges from both operating revenues and expenses.

(3) Adjustment to Test Year operations to reflect depreciation of regulatory disallowance of West Phoenix Unit 4.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(4)		(5)		(6)	
						Updated in Staff 6.55 (Supplemental)	
		Include Interest Expense on Customer Deposits		Adjust Depreciation Expense - 2010 Study		Solar Generation Post-Test Year Plant Additions	
Line No.	Description	Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	197	197	-	-	-	-
8.	Maintenance	-	-	-	-	1,935	1,869
9.	Subtotal	197	197	-	-	1,935	1,869
10.	Depreciation and Amortization			(28,646)	(32,389)	8,449	8,162
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	915	884
14.	Total	197	197	(28,646)	(32,389)	11,299	10,915
15.	Operating Income Before Income Tax	(197)	(197)	28,646	32,389	(11,299)	(10,915)
16.	Interest Expense			-	-	7,404	7,152
17.	Taxable Income	(197)	(197)	28,646	32,389	(18,703)	(18,067)
18.	Current Income Tax Rate - 39.51%	(78)	(78)	11,318	12,797	(7,390)	(7,138)
19.	Operating Income (line 15 minus line 18)	$ (119)	$ (119)	$ 17,328	$ 19,592	$ (3,909)	$ (3,777)
	WITNESS:	LA BENZ		LA BENZ		GULDNER / LA BENZ	

(4) Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits using January 2011 interest rates.

(5) Adjustment to Test Year operations to reflect depreciation expense based on the 2010 depreciation study.

(6) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income taxes associated with Solar Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 3.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(7) Updated in Staff 6.55 (Supplemental) Fossil Generation Post-Test Year Plant Additions		(8) Updated in Staff 6.55 (Supplemental) Nuclear Generation Post-Test Year Plant Additions		(9) Updated in Staff 6.55 (Supplemental) Distribution and General and Intangible Post-Test Year Plant Additions	
		Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -		$ -	$ -
2.	Revenues from Surcharges	-	-	-		-	-
3.	Other Electric Revenues	-	-	-		-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-		-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	-	-	-	-	-	-
15.	Operating Income Before Income Tax	-	-	-	-	-	-
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	-	-	-	-	-
18.	Current Income Tax Rate - 39.51%	-	-	-	-	-	-
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ -	$ -	$ -	$ -
	WITNESS:	RUCO - RADIGAN		RUCO - RADIGAN		RUCO - RADIGAN	

(7) Adjustment to Reverse inclusion of Post-Test Year Plant Additions for fossil generation

(8) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for nuclear generation estimated in service date prior to 6/30/2012.

(9) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for distribution and general and intangibles.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(10) Decommissioning and Spent Fuel Costs		(11) Updated to Reflect New Union Contract Annualize Payroll Expense		(12) Normalize Employee Benefits	
		Total Co. (S)	ACC (T)	Total Co. (U)	ACC (V)	Total Co. (W)	ACC (X)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	(4,236)	(4,133)	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	4,236	4,133	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	3,795	3,527	8,148	7,572
8.	Maintenance	-	-	1,060	985	-	-
9.	Subtotal	-	-	4,855	4,512	8,148	7,572
10.	Depreciation and Amortization	(2,947)	(2,875)	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	(2,947)	(2,875)	4,855	4,512	8,148	7,572
15.	Operating Income Before Income Tax	7,183	7,008	(4,855)	(4,512)	(8,148)	(7,572)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	7,183	7,008	(4,855)	(4,512)	(8,148)	(7,572)
18.	Current Income Tax Rate - 39.51%	2,838	2,769	(1,918)	(1,783)	(3,219)	(2,992)
19.	Operating Income (line 15 minus line 18)	$ 4,345	$ 4,239	$ (2,937)	$ (2,729)	$ (4,929)	$ (4,580)
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(10) Adjustment to Test Year operations to reflect updated decommissioning funding levels for Palo Verde due to license extension and updated ISFSI expense.

(11) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2011 employee levels, March 2011 wage levels for performance review employees and 2012 wage levels for Union employees.

(12) Adjustment to Test Year operations to reflect the current December 2010 actuarial valuation of retirement program expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(13) Normalize Income Tax Expense/Interest Synchronization Total Co. (Y)	ACC (Z)	(14) Reflects Most Current Property Tax Rates Annualize Property Tax Expense Total Co. (AA)	ACC (BB)	(15) Annualize Severance Costs Total Co. (CC)	ACC (DD)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	(6,732)	(6,256)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	(6,732)	(6,256)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	17,276	14,531	-	-
14.	Total	-	-	17,276	14,531	(6,732)	(6,256)
15.	Operating Income Before Income Tax	-	-	(17,276)	(14,531)	6,732	6,256
16.	Interest Expense	(57,259)	(47,357)	-	-	-	-
17.	Taxable Income	57,259	47,357	(17,276)	(14,531)	6,732	6,256
18.	Current Income Tax Rate - 39.51%	22,623	18,711	(6,826)	(5,741)	2,660	2,472
19.	Operating Income (line 15 minus line 18)	$ (22,623)	$ (18,711)	$ (10,450)	$ (8,790)	$ 4,072	$ 3,784
	WITNESS:	RUCO - RADIGAN		LA BENZ		LA BENZ	

(13) Adjustment to Test Year operations for income tax true-ups consistent with Staff method in 2008 APS Rate CASe

(14) Adjustment to Test Year operations to annualize property taxes calculated using the actual 2011 tax assessment ratio and tax rate.

(15) Adjustment to Test Year operations to amortize the expense associated with employees severed in 2010 over a three year period.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(16)		(17)		(18)	
		Amortize Childs-Irving Excess Decommissioning Costs		Remove Schedule 3 Revenues		Normalize Fossil Maintenance	
Line No.	Description	Total Co. (EE)	ACC (FF)	Total Co. (GG)	ACC (HH)	Total Co. (II)	ACC (JJ)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	(18,660)	(18,660)	-	
4.	Total Electric Operating Revenues	-	-	(18,660)	(18,660)	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(18,660)	(18,660)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	(4,397)	(4,290)
9.	Subtotal	-	-	-	-	(4,397)	(4,290)
10.	Depreciation and Amortization	(893)	(863)	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-		-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	(893)	(863)	-	-	(4,397)	(4,290)
15.	Operating Income Before Income Tax	893	863	(18,660)	(18,660)	4,397	4,290
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	893	863	(18,660)	(18,660)	4,397	4,290
18.	Current Income Tax Rate - 39.51%	353	341	(7,373)	(7,373)	1,737	1,695
19.	Operating Income (line 15 minus line 18)	$ 540	$ 522	$ (11,287)	$ (11,287)	$ 2,660	$ 2,595
	WITNESS:	LA BENZ		RUCO - Radigan		LA BENZ	

(16) Adjustment to amortize the excess decommissioning costs for the Childs Irving Power Plant over a three year period.

(17) Reverse Adjustment to remove revenues associated with Schedule 3 in the Test Year.

(18) Adjustment to Test Year operations to reflect normalization of fossil production maintenance expense.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(19)		(20)		(21)	
						Updated to Reflect New Pro Formas	
		Normalize Nuclear Maintenance		Annualize Four Corners Coal Reclamation Costs		Adjust Cash Working Capital for Cost of Service Pro Formas	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
		(KK)	(LL)	(MM)	(NN)	(OO)	(PP)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	3,430	3,347	-	
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(3,430)	(3,347)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	5,383	5,252	-		-	-
9.	Subtotal	5,383	5,252	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	5,383	5,252	-	-	-	-
15.	Operating Income Before Income Tax	(5,383)	(5,252)	(3,430)	(3,347)	-	-
16.	Interest Expense	-	-	-	-	(257)	(179)
17.	Taxable Income	(5,383)	(5,252)	(3,430)	(3,347)	257	179
18.	Current Income Tax Rate - 39.51%	(2,127)	(2,075)	(1,355)	(1,322)	102	71
19.	Operating Income (line 15 minus line 18)	$ (3,256)	$ (3,177)	$ (2,075)	$ (2,025)	$ (102)	$ (71)
	WITNESS:	LA BENZ		RUCO - Radigan		LA BENZ	

(19) Adjustment to Test Year operations to reflect normalization of nuclear production maintenance expense.

(20) Adjustment to APS Presentation refjecting 4 yr amortization of Four Corner Service Life of Units 1-3.

(21) Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment, as shown on Schedule RUCO B-2, page 3, column 7.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(22)		(23)		(24)	
		Remove PWEC Loan Amortization		Amortize Pension and OPEB Deferral		Normalize Pole Attachment Revenues	
Line No.	Description	Total Co. (QQ)	ACC (RR)	Total Co. (SS)	ACC (TT)	Total Co. (UU)	ACC (VV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(305)	(305)
4.	Total Electric Operating Revenues	-	-	-	-	(305)	(305)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(305)	(305)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	8,740	8,122	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	8,740	8,122	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	2,107	2,035	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	2,107	2,035	8,740	8,122	-	-
15.	Operating Income Before Income Tax	(2,107)	(2,035)	(8,740)	(8,122)	(305)	(305)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(2,107)	(2,035)	(8,740)	(8,122)	(305)	(305)
18.	Current Income Tax Rate - 39.51%	(832)	(804)	(3,453)	(3,209)	(121)	(121)
19.	Operating Income (line 15 minus line 18)	$ (1,275)	$ (1,231)	$ (5,287)	$ (4,913)	$ (184)	$ (184)
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(22) Adjustment to Test Year operations to remove PWEC loan amortization and interest authorized in Decision No. 65796 and 67744.

(23) Adjustment to Test Year operations reflect the recovery of the Pension/OPEB deferral authorized in Decision No. 71448 to be amortized over a three year period.

(24) Adjustment to Test Year Other Electric Revenues to reflect change in FCC rules impacting pole attachment fees.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		(25)		(26)		(27)	
		Remove Supplemental Executive Retirement Plan Benefits		Remove Stock Compensation		Remove Out of Period and Miscellaneous Items	
Line No.	Description	Total Co. (WW)	ACC (XX)	Total Co. (YY)	ACC (ZZ)	Total Co. (AAA)	ACC (BBB)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(7,000)	(6,830)
4.	Total Electric Operating Revenues	-	-	-	-	(7,000)	(6,830)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(7,000)	(6,830)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(8,492)	(7,892)	(12,421)	(11,543)	3,000	2,996
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(8,492)	(7,892)	(12,421)	(11,543)	3,000	2,996
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	(2,529)	(2,350)
13.	Other Taxes	-	-	-	-	-	-
14.	Total	(8,492)	(7,892)	(12,421)	(11,543)	471	646
15.	Operating Income Before Income Tax	8,492	7,892	12,421	11,543	(7,471)	(7,476)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	8,492	7,892	12,421	11,543	(7,471)	(7,476)
18.	Current Income Tax Rate - 39.51%	3,355	3,118	4,908	4,561	(2,952)	(2,954)
19.	Operating Income (line 15 minus line 18)	$ 5,137	$ 4,774	$ 7,513	$ 6,982	$ (4,519)	$ (4,522)
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(25) Adjustment to Test Year operations to remove supplemental executive retirement benefits ("SERP").

(26) Adjustment to Test Year operations to remove stock compensation.

(27) Adjustment to Test Year operations to remove legal accrual reserve, bad debt reversal accrual, grant reserve, benchmark study costs, branding costs and a non-recurring payroll expense.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(28) Updated in Staff 22.9 (Supplemental) Base Fuel and Purchased Power		(29) Test Year PSA Revenue and Deferred Fuel Amortization		(30) Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals	
		Total Co. (CCC)	ACC (DDD)	Total Co. (EEE)	ACC (FFF)	Total Co. (GGG)	ACC (HHH)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	121,231	108,669	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	121,231	108,669	-	-
5.	Electric Fuel and Purchased Power Costs	(39,385)	(39,385)	127,728	127,728	(101,790)	(101,790)
6.	Oper Rev Less Fuel & Purch Pwr Costs	39,385	39,385	(6,497)	(19,059)	101,790	101,790
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	(6,497)	(6,497)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	(6,497)	(6,497)	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	-	-	(6,497)	(6,497)	-	-
15.	Operating Income Before Income Tax	39,385	39,385	-	(12,562)	101,790	101,790
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	39,385	39,385	-	(12,562)	101,790	101,790
18.	Current Income Tax Rate - 39.51%	15,561	15,561	-	(4,963)	40,217	40,217
19.	Operating Income (line 15 minus line 18)	$ 23,824	$ 23,824	$ -	$ (7,599)	$ 61,573	$ 61,573
	WITNESS:	EWEN		EWEN		EWEN	

(28) Adjustment to Test Year Operations to include 2012 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption.

(29) Adjustment to Test Year retail operating revenues and fuel and purchased power expense to remove retail PSA revenue and amortization of deferred fuel related to prior periods.

(30) Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and mark-to-market accruals.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(31) Normalize Weather Conditions Total Co. (III)	ACC (JJJ)	(32) Annualize Customer Levels Total Co. (KKK)	ACC (LLL)	(33) Low Income Customer Discount Total Co. (MMM)	ACC (NNN)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ 10,330	$ 10,330	$ (290)	$ (290)	$ -	$ -
2.	Revenues from Surcharges			-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	10,330	10,330	(290)	(290)	-	-
5.	Electric Fuel and Purchased Power Costs	3,909	3,909	253	253	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	6,421	6,421	(543)	(543)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense			-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	-	-	-	-	-	-
15.	Operating Income Before Income Tax	6,421	6,421	(543)	(543)	-	-
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	6,421	6,421	(543)	(543)	-	-
18.	Current Income Tax Rate - 39.51%	2,537	2,537	(215)	(215)	-	-
19.	Operating Income (line 15 minus line 18)	$ 3,884	$ 3,884	$ (328)	$ (328)	$ -	$ -
	WITNESS:	MIESSNER		MIESSNER		RUCO - Radigan	

(31) Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2010.

(32) Adjustment to Test Year operations to reflect the annualization of customer levels at December 31, 2010.

(33) Reject APS Adjustment to Test Year operations to reflect the increase in low income customer discounts from the Test Year through July 2012.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(34) Removal per Staff 9.2 — Exclude Certain R&D Project Expenses — Total Co. (OOO)	ACC (PPP)	(35) Updated to Sync with FERC Filing — Sync Step-Up Transformer Costs Excluded with FERC Formula Rate — Total Co. (QQQ)	ACC (RRR)	(36) Total Income Statement Adjustments (a) — Total Co. (SSS)	ACC (TTT)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ 10,040	$ 10,040
2.	Revenues from Surcharges	-	-	-	-	(71,530)	(83,800)
3.	Other Electric Revenues	-	-	-	-	(25,965)	(25,795)
4.	Total Electric Operating Revenues	-	-	-	-	(87,455)	(99,555)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	(18,292)	(18,272)
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(69,163)	(81,283)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(2,129)	(2,057)	1,762	1,702	(189,800)	(189,008)
8.	Maintenance	-	-	-	-	3,981	3,816
9.	Subtotal	(2,129)	(2,057)	1,762	1,702	(185,819)	(185,192)
10.	Depreciation and Amortization	-	-	-	-	(24,366)	(28,283)
11.	Amortization of Gain	-	-	-	-	2,107	2,035
12.	Administrative and General	-	-	-	-	(2,529)	(2,350)
13.	Other Taxes	-	-	-	-	18,191	15,415
14.	Total	(2,129)	(2,057)	1,762	1,702	(192,416)	(198,375)
15.	Operating Income Before Income Tax	2,129	2,057	(1,762)	(1,702)	123,253	117,092
16.	Interest Expense	-	-	-	-	(50,369)	(40,632)
17.	Taxable Income	2,129	2,057	(1,762)	(1,702)	173,622	157,724
18.	Current Income Tax Rate - 39.51%	841	813	(696)	(672)	68,598	62,318
19.	Operating Income (line 15 minus line 18)	$ 1,288	$ 1,244	$ (1,066)	$ (1,030)	$ 54,655	$ 54,774

WITNESS: GULDNER FRYER

(34) Adjustment to Test Year operations to remove costs associated certain R&D projects.

(35) Adjustment to Test Year operations to sync up the step-up transformers excluded from the FERC formula rate.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

RUCO Fair Value Increment

Calculation of Fair Value Increment

	Adjusted Test Year Capital Structure		Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$	3,382,856	46.06%	6.26%	2.88%
2.	Preferred Stock		-	0.00%	0.00%	0.00%
3.	Common Equity		3,961,248	53.94%	10.00%	5.39%
4.	Short-Term Debt		-	0.00%	0.00%	0.00%
5.	Total	$	7,344,104	100.00%		8.27%

	Capital Structure with 1.5% FV Increment		Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$	3,382,856	46.06%	4.08%	1.88%
7.	Preferred Stock		-	0.00%	0.00%	0.00%
8.	Common Equity		3,961,248	53.94%	7.82%	4.22%
9.	Short-Term Debt		-	0.00%	0.00%	0.00%
10.	FVRB Increment		-	0.00%	0.00%	0.00%
11.	Total	$	7,344,104	100.00%		6.10%

	Fair Value Increment Calculation		Fair Value		Original Cost
12.	Rate Base	$	8,050,131	$	5,544,426
13.	Rate of Return		6.10%		8.27%
14.	Required Operating Income	$	491,058	$	458,524
15.	Adjusted Operating Income	$	491,057	$	491,057
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$	1	$	(32,533)
17.	Revenue Conversion Factor		1.6532		1.6532
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$	(0)	$	(53,785)
19.	Fair Value Increment	$	53,784		

RUCO Cash Working Capital Adjustment

ARIZONA PUBLIC SERVICE
INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR CWC PURPOSES
TEST YEAR ENDED 12/31/2010
(THOUSANDS OF DOLLARS)

LINE	DESCRIPTION	1 Remove Bark Beetle Remediation Amortization Total Co. (A)	2 Remove Test Year Surcharges Total Co. (C)	3 Include West Phoenix Unit 4 Regulatory Disallowance Total Co. (E)	4 Include Interest Expense on Customer Deposits Total Co. (G)	5 Adjust Depreciation Expense -2010 Study Total Co. (I)	6 Solar Generation Post-Test Year Plant Additions Total Co. (K)	7 Fossil Generation Post-Test Year Plant Additions Total Co. (M)	8 Nuclear Generation Post-Test Year Plant Additions Total Co. (O)	9 Distribution and General and Intangible Post-Test Year Plant Additions Total Co. (Q)	10 Decommissioning and Spent Fuel Costs Total Co. (S)	11 Annual Payroll Expense Total Co. (U)
1	FUEL FOR ELECTRIC GENERATION:											
2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	NATURAL GAS	-	-	-	-	-	-	-	-	-	-	-
4	GAS MTM AND FUTURES	-	-	-	-	-	-	-	-	-	-	-
5	HANDLING	-	-	-	-	-	-	-	-	-	-	-
6	FUEL OIL	-	-	-	-	-	-	-	-	-	-	-
7	NUCLEAR:											
8	AMORTIZATION	-	-	-	-	-	-	-	-	-	-	-
9	SPENT FUEL	-	-	-	-	-	-	-	-	-	(4,236)	-
10	TOTAL NUCLEAR FUEL	-	-	-	-	-	-	-	-	-	(4,236)	-
11												
12	TOTAL FUEL	-	-	-	-	-	-	-	-	-	(4,236)	-
13												
14	PURCHASED POWER	-	(8,201)	-	-	-	-	-	-	-	-	-
15	POWER MTM	-	-	-	-	-	-	-	-	-	-	-
16	POWER SUPPLY ADJUSTER	-	-	-	-	-	-	-	-	-	-	-
17	TRANSMISSION BY OTHERS	-	-	-	-	-	-	-	-	-	-	-
18	TOTAL PURCHASED POWER & TRANS	-	(8,201)	-	-	-	-	-	-	-	-	-
19												
20	TOTAL FUEL AND PURCHASED POWE	-	(8,201)	-	-	-	-	-	-	-	(4,236)	-
21												
22	OTHER OPERATIONS & MAINTENANCE:											
23	PAYROLL	-	-	-	-	-	1,935	-	-	-	-	4,855
24	INCENTIVE	-	-	-	-	-	-	-	-	-	-	-
25	STOCK COMPENSATION	-	-	-	-	-	-	-	-	-	-	-
26	SEVERANCE (EXCLUDES PENSION)	-	-	-	-	-	-	-	-	-	-	-
27	PENSION AND OPEB	-	-	-	-	-	-	-	-	-	-	-
28	EMPLOYEE BENEFITS	-	-	-	-	-	-	-	-	-	-	-
29	PAYROLL TAXES	-	-	-	-	-	-	-	-	-	-	-
30	MATERIALS & SUPPLIES	-	-	-	-	-	-	-	-	-	-	-
31	VEHICLE LEASE PAYMENTS	-	-	-	-	-	-	-	-	-	-	-
32	PREPAID VEHICLE LICENSES	-	-	-	-	-	-	-	-	-	-	-
33	RENTS	-	-	-	-	-	-	-	-	-	-	-
34	PREPAID RENTS	-	-	-	-	-	-	-	-	-	-	-
35	PALO VERDE LEASE	-	-	-	-	-	-	-	-	-	-	-
36	PALO VERDE S/L GAIN AMORT	-	-	-	-	-	-	-	-	-	-	-
37	INSURANCE	-	-	-	-	-	-	-	-	-	-	-
38	OTHER	(1,918)	(177,253)	-	197	-	-	-	-	-	-	-
39	TOTAL	(1,918)	(177,253)	-	197	-	1,935	-	-	-	-	4,855
40												
41	DEPRECIATION & AMORTIZATION	-	-	(329)	-	(28,646)	8,449	-	-	-	(2,947)	-
42	AMORT OF PROP LOSSES & REG STUI	-	-	-	-	-	-	-	-	-	-	-
43	TOTAL	-	-	(329)	-	(28,646)	8,449	-	-	-	(2,947)	-
44												
45	INCOME TAXES:											
46	CURRENT:											
47	FEDERAL	-	(2,380)	-	(64)	-	(3,340)	-	-	-	-	(1,581)
48	STATE	-	(507)	-	(14)	-	(711)	-	-	-	-	(337)
49	DEFERRED	758	-	232	-	11,318	(3,338)	-	-	-	2,838	-
50	TOTAL	758	(2,887)	232	(78)	11,318	(7,389)	-	-	-	2,838	(1,918)
51												
52	OTHER TAXES:											
53	PROPERTY TAXES	-	-	-	-	-	915	-	-	-	-	-
54	SALES TAXES	-	-	-	-	-	-	-	-	-	-	-
55	FRANCHISE TAXES	-	-	-	-	-	-	-	-	-	-	-
56	TOTAL	-	-	-	-	-	915	-	-	-	-	-
57												
58	INTEREST EXPENSE - SYNCHRONIZED	-	-	(257)	-	-	7,404	-	-	-	-	-
59												
60	TOTAL	$ (1,160)	$ (188,341)	$ (354)	$ 119	$ (17,328)	$ 11,314	$ -	$ -	$ -	$ (4,345)	$ 2,937

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ARIZONA PUBLIC SERVICE
INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR CWC PURPOSES
TEST YEAR ENDED 12/31/2010
(THOUSANDS OF DOLLARS)

LINE	DESCRIPTION	12 Normalize Employee Benefits	13 Normalize Income Tax Expense/Interest Synchronization	14 Annualize Property Tax Expense	15 Severance Amortization	16 Amortize Childs Irving Excess Decommissioning Costs	17 Remove Schedule 3 Revenues	18 Normalize Fossil Maintenance	19 Normalize Nuclear Maintenance	20 Annualize Four Corners Coal Reclamation Costs	21 Adjust Cash Working Capital for Cost of Service Pro Formas	22 Remove PWEC Loan Amortization	23 Amortize Pension and OPEB Deferral	24 Normalize Pole Attachment Revenues
		Total Co. (W)	Total Co. (Y)	Total Co. (AA)	Total Co. (CC)	Total Co. (EE)	Total Co. (GG)	Total Co. (II)	Total Co. (KK)	Total Co. (MM)	Total Co. (OO)	Total Co. (QQ)	Total Co. (SS)	Total Co. (UU)
1	FUEL FOR ELECTRIC GENERATION:													
2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,430	$ -	$ -	$ -	$ -
3	NATURAL GAS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	GAS MTM AND FUTURES	-	-	-	-	-	-	-	-	-	-	-	-	-
5	HANDLING	-	-	-	-	-	-	-	-	-	-	-	-	-
6	FUEL OIL	-	-	-	-	-	-	-	-	-	-	-	-	-
7	NUCLEAR:													
8	AMORTIZATION	-	-	-	-	-	-	-	-	-	-	-	-	-
9	SPENT FUEL	-	-	-	-	-	-	-	-	-	-	-	-	-
10	TOTAL NUCLEAR FUEL	-	-	-	-	-	-	-	-	-	-	-	-	-
11														
12	TOTAL FUEL	-	-	-	-	-	-	-	-	3,430	-	-	-	-
13														
14	PURCHASED POWER	-	-	-	-	-	-	-	-	-	-	-	-	-
15	POWER MTM	-	-	-	-	-	-	-	-	-	-	-	-	-
16	POWER SUPPLY ADJUSTER	-	-	-	-	-	-	-	-	-	-	-	-	-
17	TRANSMISSION BY OTHERS	-	-	-	-	-	-	-	-	-	-	-	-	-
18	TOTAL PURCHASED POWER & TRANS	-	-	-	-	-	-	-	-	-	-	-	-	-
19														
20	TOTAL FUEL AND PURCHASED POWEI	-	-	-	-	-	-	-	-	3,430	-	-	-	-
21														
22	OTHER OPERATIONS & MAINTENANCE													
23	PAYROLL	-	-	-	-	-	-	-	-	-	-	-	-	-
24	INCENTIVE	-	-	-	-	-	-	-	-	-	-	-	-	-
25	STOCK COMPENSATION	-	-	-	-	-	-	-	-	-	-	-	-	-
26	SEVERANCE (EXCLUDES PENSION)	-	-	-	(6,732)	-	-	-	-	-	-	-	-	-
27	PENSION AND OPEB	8,148	-	-	-	-	-	-	-	-	-	-	8,740	-
28	EMPLOYEE BENEFITS	-	-	-	-	-	-	-	-	-	-	-	-	-
29	PAYROLL TAXES	-	-	-	-	-	-	-	-	-	-	-	-	-
30	MATERIALS & SUPPLIES	-	-	-	-	-	-	-	-	-	-	-	-	-
31	VEHICLE LEASE PAYMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
32	PREPAID VEHICLE LICENSES	-	-	-	-	-	-	-	-	-	-	-	-	-
33	RENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
34	PREPAID RENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
35	PALO VERDE LEASE	-	-	-	-	-	-	-	-	-	-	-	-	-
36	PALO VERDE S/L GAIN AMORT	-	-	-	-	-	-	-	-	-	-	-	-	-
37	INSURANCE	-	-	-	-	-	-	-	-	-	-	-	-	-
38	OTHER	-	-	-	-	-	-	(4,397)	5,383	-	-	-	-	-
39	TOTAL	8,148	-	-	(6,732)	-	-	(4,397)	5,383	-	-	-	8,740	-
40														
41	DEPRECIATION & AMORTIZATION	-	-	-	-	(893)	-	-	-	-	-	2,107	-	-
42	AMORT OF PROP LOSSES & REG STUI	-	-	-	-	-	-	-	-	-	-	-	-	-
43	TOTAL	-	-	-	-	(893)	-	-	-	-	-	2,107	-	-
44														
45	INCOME TAXES:													
46	CURRENT:													
47	FEDERAL	-	19,592	(5,628)	1,541	-	-	1,432	(1,754)	-	129	-	-	(100)
48	STATE	-	4,170	(1,198)	328	-	-	305	(373)	-	27	-	-	(21)
49	DEFERRED	(3,219)	-	-	791	353	-	-	-	(1,355)	-	(832)	(3,453)	-
50	TOTAL	(3,219)	23,762	(6,826)	2,660	353	-	1,737	(2,127)	(1,355)	156	(832)	(3,453)	(121)
51														
52	OTHER TAXES:													
53	PROPERTY TAXES	-	-	17,276	-	-	-	-	-	-	-	-	-	-
54	SALES TAXES	-	-	-	-	-	-	-	-	-	-	-	-	-
55	FRANCHISE TAXES	-	-	-	-	-	-	-	-	-	-	-	-	-
56	TOTAL	-	-	17,276	-	-	-	-	-	-	-	-	-	-
57														
58	INTEREST EXPENSE - SYNCHRONIZED	-	(60,142)	-	-	-	-	-	-	-	(396)	-	-	-
59														
60	TOTAL	$ 4,929	$ (36,380)	$ 10,450	$ (4,072)	$ (540)	$ -	$ (2,660)	$ 3,256	$ 2,075	$ (240)	$ 1,275	$ 5,287	$ (121)

ARIZONA PUBLIC SERVICE
INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR CWC PURPOSES
TEST YEAR ENDED 12/31/2010
(THOUSANDS OF DOLLARS)

LINE	DESCRIPTION	25 Remove Supplemental Executive Retirement Plan Benefits	26 Remove Stock Compensation	27 Remove Out of Period and Miscellaneous Items	28 Base Fuel and Purchased Power	29 Test Year PSA Revenue and Deferred Fuel Amortization	30 Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals	31 Normalize Weather Conditions	32 Annualize Customer Levels	33 Low Income Customer Discount	34 Exclude R&D Project Expenses	35 Sync Step-Up Transformer Costs Excluded with FERC Formula Rate	36 Total Income Statement Adjustments (a)
		Total Co. (WW)	Total Co. (YY)	Total Co. (AAA)	Total Co. (CCC)	Total Co. (EEE)	Total Co. (GGG)	Total Co. (III)	Total Co. (KKK)	Total Co. (MMM)	Total Co. (MMM)	Total Co. (MMM)	Total Co. (OOO)
1	FUEL FOR ELECTRIC GENERATION:												
2	COAL	$ -	$ -	$ -	$ 45,258	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,688
3	NATURAL GAS			-	(83,112)	-	-	3,909	253	-	-	-	(78,950)
4	GAS MTM AND FUTURES	-	-	-	-	-	-	-	-	-	-	-	-
5	HANDLING	-	-	-	(139)	-	-	-	-	-	-	-	(139)
6	FUEL OIL	-	-	-	-	-	-	-	-	-	-	-	-
7	NUCLEAR:												
8	AMORTIZATION	-	-	-	9,714	-	-	-	-	-	-	-	9,714
9	SPENT FUEL	-	-	-	-	-	-	-	-	-	-	-	(4,236)
10	TOTAL NUCLEAR FUEL	-	-	-	9,714	-	-	-	-	-	-	-	5,478
11													-
12	TOTAL FUEL	-	-	-	(28,279)	-	-	3,909	253	-	-	-	(24,923)
13													
14	PURCHASED POWER	-	-	-	(16,533)	-	-	-	-	-	-	-	(24,734)
15	POWER MTM	-	-	-	-	-	-	-	-	-	-	-	-
16	POWER SUPPLY ADJUSTER	-	-	-	-	115,166	(101,790)	-	-	-	-	-	13,376
17	TRANSMISSION BY OTHERS	-	-	-	5,427	-	-	-	-	-	-	-	5,427
18	TOTAL PURCHASED POWER & TRANS	-	-	-	(11,106)	115,166	(101,790)	-	-	-	-	-	(5,931)
19													
20	TOTAL FUEL AND PURCHASED POWE	-	-	-	(39,385)	115,166	(101,790)	3,909	253	-	-	-	(30,854)
21													
22	OTHER OPERATIONS & MAINTENANCE												
23	PAYROLL	-	-	-	-	-	-	-	-	-	-	-	6,790
24	INCENTIVE	-	-	-	-	-	-	-	-	-	-	-	-
25	STOCK COMPENSATION	-	(12,421)	-	-	-	-	-	-	-	-	-	(12,421)
26	SEVERANCE (EXCLUDES PENSION)	-	-	-	-	-	-	-	-	-	-	-	(6,732)
27	PENSION AND OPEB	(8,492)	-	-	-	-	-	-	-	-	-	-	8,396
28	EMPLOYEE BENEFITS	-	-	-	-	-	-	-	-	-	-	-	-
29	PAYROLL TAXES	-	-	-	-	-	-	-	-	-	-	-	-
30	MATERIALS & SUPPLIES	-	-	-	-	-	-	-	-	-	-	-	-
31	VEHICLE LEASE PAYMENTS	-	-	-	-	-	-	-	-	-	-	-	-
32	PREPAID VEHICLE LICENSES	-	-	-	-	-	-	-	-	-	-	-	-
33	RENTS	-	-	-	-	-	-	-	-	-	-	-	-
34	PREPAID RENTS	-	-	-	-	-	-	-	-	-	-	-	-
35	PALO VERDE LEASE	-	-	-	-	-	-	-	-	-	-	-	-
36	PALO VERDE S/L GAIN AMORT	-	-	-	-	-	-	-	-	-	-	-	-
37	INSURANCE	-	-	-	-	-	-	-	-	-	-	-	-
38	OTHER	-	-	471	-	(6,497)	-	-	-	-	(2,129)	1,762	(184,014)
39	TOTAL	(8,492)	(12,421)	471	-	(6,497)	-	-	-	-	(2,129)	1,762	(187,981)
40													
41	DEPRECIATION & AMORTIZATION	-	-	-	-	-	-	-	-	-	-	-	(22,259)
42	AMORT OF PROP LOSSES & REG STUI	-	-	-	-	-	-	-	-	-	-	-	-
43	TOTAL	-	-	-	-	-	-	-	-	-	-	-	(22,259)
44													
45	INCOME TAXES:												
46	CURRENT:												
47	FEDERAL	-	-	-	12,830	39,493	-	2,092	(177)	-	693	(574)	62,085
48	STATE	-	-	-	2,731	8,406	-	445	(38)	-	148	(122)	13,213
49	DEFERRED	3,355	4,908	(2,852)	-	(47,899)	40,217	-	-	-	-	-	1,722
50	TOTAL	3,355	4,908	(2,852)	15,561	-	40,217	2,537	(215)	-	841	(696)	77,020
51													
52	OTHER TAXES:												
53	PROPERTY TAXES	-	-	-	-	-	-	-	-	-	-	-	18,191
54	SALES TAXES	-	-	-	-	-	-	-	-	-	-	-	-
55	FRANCHISE TAXES	-	-	-	-	-	-	-	-	-	-	-	-
56	TOTAL	-	-	-	-	-	-	-	-	-	-	-	18,191
57													
58	INTEREST EXPENSE - SYNCHRONIZEC	-	-	-	-	-	-	-	-	-	-	-	(53,391)
59													
60	TOTAL	$ (5,137)	$ (7,513)	$ (2,481)	$ (23,824)	$ 108,669	$ (61,573)	$ 6,446	$ 38	$ -	$ (1,288)	$ 1,066	$ (199,274)

ARIZONA PUBLIC SERVICE
INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR CWC PURPOSES
TEST YEAR ENDED 12/31/2010
(THOUSANDS OF DOLLARS)

		37	38
		CWC Factor	Total CWC Adjustment
LINE	DESCRIPTION	CWC Factor	Total Co. (OOO)
1	FUEL FOR ELECTRIC GENERATION:		
2	COAL	0.010820	$ 527
3	NATURAL GAS	0.011200	(884)
4	GAS MTM AND FUTURES	0.000000	-
5	HANDLING	0.062510	(9)
6	FUEL OIL	-0.002900	-
7	NUCLEAR:		-
8	AMORTIZATION	0.000000	-
9	SPENT FUEL	-0.106690	452
10	TOTAL NUCLEAR FUEL		452
11			
12	TOTAL FUEL		86
13			
14	PURCHASED POWER	0.008890	(220)
15	POWER MTM	0.000000	-
16	POWER SUPPLY ADJUSTER	0.000000	-
17	TRANSMISSION BY OTHERS	-0.001700	(9)
18	TOTAL PURCHASED POWER & TRANS		(229)
19			
20	TOTAL FUEL AND PURCHASED POWEI		(143)
21			
22	OTHER OPERATIONS & MAINTENANCE		
23	PAYROLL	0.062510	424
24	INCENTIVE	-0.545410	-
25	STOCK COMPENSATION	0.000000	-
26	SEVERANCE (EXCLUDES PENSION)	-0.110900	747
27	PENSION AND OPEB	-0.000250	(2)
28	EMPLOYEE BENEFITS	0.067080	-
29	PAYROLL TAXES	-0.005200	-
30	MATERIALS & SUPPLIES	0.035790	-
31	VEHICLE LEASE PAYMENTS	0.067040	-
32	PREPAID VEHICLE LICENSES	0.000000	-
33	RENTS	0.070450	-
34	PREPAID RENTS	0.000000	-
35	PALO VERDE LEASE	-0.211330	-
36	PALO VERDE S/L GAIN AMORT	0.000000	-
37	INSURANCE	0.000000	-
38	OTHER	0.028120	(5,174)
39	TOTAL		(4,006)
40			
41	DEPRECIATION & AMORTIZATION	0.000000	-
42	AMORT OF PROP LOSSES & REG STUI	0.000000	-
43	TOTAL		-
44			
45	INCOME TAXES:		
46	CURRENT:		
47	FEDERAL	-0.058970	(3,661)
48	STATE	-0.074430	(983)
49	DEFERRED	0.000000	-
50	TOTAL		(4,645)
51			
52	OTHER TAXES:		
53	PROPERTY TAXES	-0.475170	(8,644)
54	SALES TAXES	-0.061510	-
55	FRANCHISE TAXES	-0.101320	-
56	TOTAL		(8,644)
57			
58	INTEREST EXPENSE - SYNCHRONIZEC	-0.159240	8,502
59			
60	TOTAL		$ (8,935)
		Cost of Debt	2.88%
		Synchronized Interest	(257)

RUCO Pro-Forma Income Tax Calculation and Interest Expense Synchronization

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustment to Operating Income as Shown on Schedule C-2, page 5, column 13
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: INCOME TAXES

Line No.	Description		Amount	RUCO
1.	Operating Income Before Income Tax		$ -	$ -
2.	Interest Expense and Other Net Deductions		(60,142)	(57,259)
3.	**Taxable Income**		-	-
4.	**Income Tax at 39.51%**	**JCL_WP25 page 2 [A]**	**23,762**	**22,623**
5.	Deferred Tax		-	-
6.	**Operating Income After Tax**		**$ (23,762)**	**$ (22,623)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustment as Shown on Schedule C-2, page 5, column 13.
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: INCOME TAXES

Line No.	Description	APS	RUCO	
1.	**Pre-Tax Operating Income (SFR Schedule C-1, line 11 + line 8)**	$ 692,521	$ 692,521	
2.	**Allocated Interest Expense (unadjusted rate base * cost of debt)**	(189,176)	(192,059)	**RUCO adjusted rate base times RUCO Long term debt rate**
3.	**Adjusted Operating Income**	503,345	500,462	
4.	**Gross Income Tax at 39.51%**	198,872	197,732	
5.	**Tax Effected Permanent Items**			
6.	Meals and Entertainment	669	669	
7.	Non-Deductible Compensation	58	58	
8.	Research & Development Credit	(2,667)	(2,667)	
9.	Amortization of OPEB Subsidy PPACA	1,004	1,004	
10.	Other Federal Tax Credits (Net)	(16)	(16)	
11.	Amortization of FAS109 Liability	(13)	(13)	
12.	Arizona Tax Credits	(641)	(641)	
13.	Depreciation on AFUDC	1,936	1,936	
14.	**Net On-Going Tax Expense**	199,202	198,062	
15.	**Actual Test Year Tax Expense (SFR Schedule C-1, line 8)**	175,440	175,440	
16.	**Tax Pro Forma Adjustment**	$ 23,762 [A]	$ 22,623	

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.15: Four Corners Reclamation costs. Refer to JCL_WP32 and Mr. La Benz' direct testimony at pages 28-29.

a. Provide the August 2010 Marston study.

b. Please confirm that APS' request for Four Corners Coal Reclamation costs is based on a four year amortization, wherein, as shown on JCL-WP32, page 27, APS proposes to amortize $25,122,294 over four years starting on July 1, 2012. If this is not accurate, explain fully.

c. Please provide the documents and orders upon which APS has relied for its assumption that the Four Corners Units 1-3 reclamation costs will be incurred from July 1, 2012 through June 30, 2016.

d. Please explain fully why the reclamation for Four Corners Units 1-3 cannot be done at the same time as the reclamation for Four Corners Units 4 and 5.

e. Please provide a calculation, similar to JCL_WP32, page 2 of 7, but which escalates the reclamation costs for Four Corners Units 1-3 through 6/30/2038 and bases the annual amortization amount on a 26 year amortization, similar to the reclamation cost amortization for Four Corners Units 4-5.

f. Are the mines and source of coal from BHP Billiton the same for Four Corners Units 1-3 and Four Corners Units 4-5? If not, please explain.

g. Please identify the coal source/mines, c ontract(s), a nd annual purchase tonnage commitments for each such contract in place during 2010 to serve Four Corners Units 1-3.

h. Please identify the coal source/mines, contract(s) and annual purchase tonnage commitments for each such contract in place during 2010 to serve Four Corners Units 4-5.

i. Please identify and explain how the coal source/mines, contract(s), and annual purchase tonnage commitments for each current coal supply contract currently serving Four Corners Units 1-3 and Units 4-5 would be affected by the retirement of Units 1-3 and extended operating life of Units 4-5.

j. Would any of the coal supply currently serving Four Corners Units 1-3 be used or usable to supply Four Corners Units 4-5 if the useful life of Units 4-5 is extended through 2038? If not, explain fully why not. If so, please explain how that would occur.

Witness: Jay La Benz

Four Corners Coal Reclamation
Pro Forma - Regulatory Liability

			Units 1-3	Units 4-5	Total	
1	Marston Study Final Reclamation Direct Costs [1]		$ 52,151,708	$ 18,516,490	$ 70,668,198	
2	Marston Study Final Reclamation Indirect Costs[1]		6,996,544	2,484,127	9,480,671	
3	Taxes & Royalties ((Line 1 + Line 2) * 19.753%)	B1[3/]	11,683,259	4,148,147	15,831,406	
4	Total Final Reclamation as of 12/31/2010		70,831,511	25,148,764	95,980,275	
5	Escalated Total Final Reclamation[2]	A1[4/]	73,959,382	49,593,293	123,552,675	
6	Actual amount accrued through mid 2012	B1[4/]	48,837,088	17,339,633	66,176,721	
7	Amount to be recovered as of 7/1/2012		25,122,294	32,253,660	57,375,954	
8	Rate Recovery 4-26 years (7/1/2012-6/30/2038 (Line 6 / 4 and 26))[3] (Recovery period reflects term of the BHP coal contract)		6,280,573	1,240,525	7,521,099	
9	Less Test Year Expense	A1[5/]	963,011	341,917	1,304,928	
10	Pro Forma Adjustment		$ 5,317,563	$ 898,608	$ 6,216,171	A1

[1] APS' share of Four Corners Units 1-3 is approximately 30% and 10% for Units 4-5 of the total August 2010 Marston study.

[2] Escalation calculated at 2.5% as of 1/1/2011 through 9/30/2012 for U 1-3 and through 6/30/2038 for U 4-5

[3] Four Corners Units 1-3 have a 4 year recovery period and account for approximately 74% of the costs. Four Corners Units 4-5 have a 26 year recovery period and account for approximately 26% of the costs.

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.15: Four Corners Reclamation costs. Refer to JCL_WP32 and Mr. La Benz' direct testimony at pages 28-29.

a. Provide the August 2010 Marston study.

b. Please confirm that APS' request for Four Corners Coal Reclamation costs is based on a four year amortization, wherein, as shown on JCL-WP32, page 27, APS proposes to amortize $25,122,294 over four years starting on July 1, 2012. If this is not accurate, explain fully.

c. Please provide the documents and orders upon which APS has relied for its assumption that the Four Corners Units 1-3 reclamation costs will be incurred from July 1, 2012 through June 30, 2016.

d. Please explain fully why the reclamation for Four Corners Units 1-3 cannot be done at the *same time* as the reclamation for Four Corners Units 4 and 5.

e. Please provide a calculation, similar to JCL_WP32, page 2 of 7, but which escalates the reclamation costs for Four Corners Units 1-3 through 6/30/2038 and bases the annual amortization amount on a 26 year amortization, similar to the reclamation cost amortization for Four Corners Units 4-5.

f. Are the mines and source of coal from BHP Billiton the same for Four Corners Units 1-3 and Four Corners Units 4-5? If not, please explain.

g. Please identify the coal source/mines, contract(s), and annual purchase tonnage commitments for each such contract in place during 2010 to serve Four Corners Units 1-3.

h. Please identify the coal source/mines, contract(s) and annual purchase tonnage commitments for each such contract in place during 2010 to serve Four Corners Units 4-5.

i. Please identify and explain how the coal source/mines, contract(s), and annual purchase tonnage commitments for each current coal supply contract currently serving Four Corners Units 1-3 and Units 4-5 would be affected by the retirement of Units 1-3 and extended operating life of Units 4-5.

j. Would any of the coal supply currently serving Four Corners Units 1-3 be used or usable to supply Four Corners Units 4-5 if the useful life of Units 4-5 is extended through 2038? If not, explain fully why not. If so, please explain how that would occur.

Witness: Jay La Benz

Staff 25.15:

k. Will the coal supply contract for Four Corners Units 4-5 be extended or renegotiated if those units operate through 2038.

l. Refer to JCL_WP32, page 2 of 7. Please provide notes 4 and 5, which are referenced on lines 5 and 6, and on line 9, respectively.

m. Why has APS used a 2.5% escalation rate on JCL_WP32, page 2 of 7 for Four Corners coal reclamation costs, but a 2.0% escalation rate on Exhibit REW-2, Statement G, page 70 for dismantlement costs?

n. Provide all support APS relied upon for the 2.5% escalation rate on JCL_WP32, page 2 of 7.

o. For each contract for coal supply serving Four Corners, please identify the coal contract provisions that relate to reclamation costs.

p. Please provide the excerpts of the coal contracts for the provisions that relate to reclamation costs, identified in part o.

q. Will the coal reclamation work be done by APS employees or contractors? Explain.

r. Has APS issued any RFPs or solicitations related to Four Corners Units 1-3 coal reclamation work? If not, explain fully why not. If so, please identify and describe the RFPs and solicitations, indicate when they were issued, and explain whether APS has received any responses.

Response:

a. Please refer to APS's response to Pre-filed 1.29 APS14149.

b. Yes, for the Four Corners Units 1-3 portion of Coal Reclamation costs, APS proposes to amortize $25,122,294 over four years starting on July 1, 2012.

c. Assuming that Four Corners Units 1-3 will cease operations at the end of the current coal contract, that will occur by July 6, 2016, APS is under a contract with BHP, which requires APS to fund to BHP the final reclamation costs related to the closing units prior to final closure of those units. Please see the relevant portion of the BHP contract attached as APS14980. Please note the attachment is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jay La Benz

Response to Staff 25.15 Continued:

d. The final physical reclamation of the mine will begin when coal is no longer provided out of the mine for any Four Corners Unit. However, under the assumption that Four Corners Units 1-3 cease operation in 2016, APS ,under the contract with BHP, is required to fund an escrow account for the final reclamation costs related to the closing units prior to those units ceasing operation. The costs for the closing units would be apportioned based upon the historical production volumes for Units 1-3 (APS owned) and Units 4/5 (Participant owned). Please see response to (i) and (p) for related contract details.

e. See attached schedules, as APS14981, reflecting pro forma escalating the reclamation costs for Four Corners Unit 1-3 through 6/30/2038.

f. Yes, the mines and source of coal from BHP Billiton are the same for Four Corners Units 1-3 and Four Corners Units 4-5.

g. The BHP Navajo Coal Company is the sole source provider of coal to the Four Corners Power Plant Units 1-5, with supply sourced from the BHP Navajo Mine. The coal is provided under the terms of the "Four Corners Coal Supply Agreement".

Responsibility for the minimum Base Annual Requirement among the Units 1-5 is allocated as follows:

- Plant Units 1, 2, and 3 shall be responsible for 34 x 10^12 Btu/year of the Base Annual Requirement (approx. 1.91M tons)

- Plant Units 4 and 5 shall be responsible for 80 x 10^12 Btu/year of the Base Annual Requirement (approx. 4.49M tons)

h. Please see response (g).

i. The current "Four Corner Coal Supply Agreement" expires July 6, 2016. An extended operating life for Units 4-5 will require the negotiation of a new or extended coal supply agreement for future years.

If Units 1-3 are retired prior to 2016, there will be two provisions of the current agreement that will require

Response to Staff 25.15 Continued:

attention. These are:

Shortfall in the purchase of the base annual tonnage requirement. The current minimum purchase requirement is approx. 6.4 M tons/year. APS Units 1-3 have a minimum purchase requirement of 1.91M tons/year. To the extent that the annual purchase obligation to BHP falls short of 6.4 M tons/yr., an accounting for the shortfall will be required. Over the past 10 years, Units 4/5 have burned approximately 5.9M tons/yr.

Final Reclamation Liability. An estimate and agreement of the amount of final reclamation liability for the BHP Navajo Mine will need to be made at the time of the early retirement of Units 1-3. The allocation of Units 1-3 share of this liability will be calculated and will be funded into an escrow account that is currently established for this purpose. The escrow account will remain under the control of APS until the BHP Navajo Mine ceases production and the final reclamation payment for Units 1-5 is made to BHP. This final reclamation payment will be based upon an estimate of final reclamation liability at the time of mine closure (which will be different than the liability estimated at the time of retirement of Units 1-3).

j. The coal supply reserve serving Four Corners Units 1-3 and Unit 4-5 is the same.

k. An extended operating life for Units 4-5 will require the negotiation of a new or extended coal supply agreement for those units to operate through 2038.

l. References A1[4/], B1[4/] and A1[5/] do not refer to notes but rather "tick marks" to numbers on pages 6 of 7, 4 of 7 and 7 of 7 respectively.

m. The 2.5% escalation rate on JCL_WP32, page 2 of 7 for Four Corners coal reclamation costs in based on the average CPI for year 2000 through 2010. The 2.0% escalation rate for dismantlement costs is based on the rate utilized in APS Asset Retirement Obligation calculation model for removal/decommissioning of long lived assets. The activities performed for mine reclamation versus plant dismantlement would be different; thus the escalation rates would not necessarily be the same.

Witness: Jay La Benz

Response to Staff 25.15 Continued:

n. Please see attached APS14982 for support of the 2.5% escalation rate.

o. Sections 4.1(a), 4.1(c)(ii) and Section 4.5 in the coal supply contract with BHP Navajo Coal Company relate to provisions for final reclamation costs.

p. Please see APS14980, attached, for excerpts of the coal contract for provisions relating to reclamation costs. Please note the attachment is *confidential* and is being provided pursuant to an executed protective agreement.

q. No, the performance of the reclamation activities are the responsibility of BHP.

r. No, the performance of the reclamation activities are the responsibility of BHP.

Witness: Jay La Benz

Operating Income Proforma Adjustment
FC Coal Reclamation
(Dollars in Thousands)
STF 25.15 e

Line No.	Description		Annualize Four Corners Coal Reclamation
1	Electric Operating Revenues		-
2	Fuel Expense	A1[2/]	3,430
3	Oper Rev Less Fuel		(3,430)
	Other Operating Expenses:		
4	Operations Excluding Fuel Expenses		-
5	Maintenance		-
6	Subtotal		-
7	Depreciation		-
8	Amortization of Gain		-
9	Administrative and General		-
10	Other Taxes		-
11	Total		-
12	Operating Income		(3,430)
13	Net Deductions		-
14	Interest		-
15	Taxable Income		(3,430)
16	Current Income Tax Rate - 39.51%		(1,355)
17	Deferred Tax		-
18	Net Income		(2,075)

Purpose: Adjustment to annual coal reclamation amortization due to increase in final reclamation costs based on study completed by Marston in August 2010. Also, adjustment to amortization period f of reclamation from 2016 to 2038 for assumed extension of coal agreement.

Four Corners Coal Reclamation
Pro Forma - Regulatory Liability
For STF25.15 e

				Units 1-3		Units 4-5		Total	
1	Marston Study Final Reclamation Direct Costs [1]		$	52,151,708	$	18,516,490	$	70,668,198	
2	Marston Study Final Reclamation Indirect Costs[1]			6,996,544		2,484,127		9,480,671	
3	Taxes & Royalties ((Line 1 + Line 2) * 19.753%)	B1[3/]		11,683,259		4,148,147		15,831,406	
4	Total Final Reclamation as of 12/31/2010			70,831,511		25,148,764		95,980,275	
5	Escalated Total Final Reclamation[2]	A1[4/]		139,679,543		49,593,293		189,272,836	
6	Actual amount accrued through mid 2012	B1[4/]		48,837,088		17,339,633		66,176,721	
7	Amount to be recovered as of 7/1/2012			90,842,455		32,253,660		123,096,115	
8	Rate Recovery 26 years (7/1/2012-6/30/2038 (Line 6 / 26))[3] (Recovery period reflects term of the BHP coal contract)			3,493,941		1,240,525		4,734,466	
9	Less Test Year Expense	A1[5/]		963,011		341,917		1,304,928	
10	Pro Forma Adjustment		$	2,530,930	$	898,608	$	3,429,538	A1

1 APS' share of Four Corners Units 1-3 is approximately 30% and 10% for Units 4-5 of the total August 2010 Marston study.
2 Escalation calculated at 2.5% as of 1/1/2011 through 6/30/2038 for U 1-5
3 Four Corners Units 1-3 have a 26 year recovery period and account for approximately 74% of the costs.
Four Corners Units 4-5 have a 26 year recovery period and account for approximately 26% of the costs.

Four Corners
Coal Reclamation
Taxes, Royalties and Indirects (Rates applied to Coal)
STF 25.15 e

Royalty	12.500%	
Business Activity Tax	5.000%	
New Mexico Gross Receipts Tax	6.313%	
BAT Credit	-1.250%	
GRT Credit	-3.750%	
Conservation & Resource ExciseTax	0.940%	
Total	19.753%	**B1**

Four Corners Coal Reclamation
Projected Balances in Regulatory Asset and Coal Reclamation Liability
STF 25.15 e

Income Statement	2002	2003	2004	2005	2006	2007	2008	2009
1 2002/Decision 67744 (4/1/2005)	636,635.00	636,636.86	636,845.30	636,845.05	636,773.15	318,422.52		
2 TY 9/30/2005 Decision # 69663 (7/1/2007)						652,463.52	1,304,927.04	978,695.28
3 TY 12/31/2007 (10/1/2009)								326,231.76
4 TY 12/31/2010 (7/1/2012)								
5 Total	636,635.00	636,636.86	636,845.30	636,845.05	636,773.15	970,886.04	1,304,927.04	1,304,927.04
Balance Sheet								
Account 1823 - Regulatory Asset								
6 Beginning Balance	-	-	-	-	13,033,650.00	12,396,804.96	11,425,918.92	10,120,991.88
7 Debit	-	-	-	13,033,650.00				
8 Credit	-	-	-	-	(636,845.04)	(970,886.04)	(1,304,927.04)	(1,304,927.04)
9 Ending Balance	-	-	-	13,033,650.00	12,396,804.96	11,425,918.92	10,120,991.88	8,816,064.84
Account 2530 - Liability								
10 Beginning Balance	(56,149,855.60)	(56,786,490.60)	(57,423,127.46)	(58,059,972.76)	(71,730,467.81)	(71,730,467.81)	(71,730,467.81)	(71,730,467.81)
11 Debit	-	-	-	-				
12 Credit	(636,635.00)	(636,636.86)	(636,845.30)	(13,670,495.05)				
13 Ending Balance	(56,786,490.60)	(57,423,127.46)	(58,059,972.76)	(71,730,467.81)	(71,730,467.81)	(71,730,467.81)	(71,730,467.81)	(71,730,467.81)
Net Balance Sheet	(56,786,490.60)	(57,423,127.46)	(58,059,972.76)	(58,696,817.81)	(59,333,662.85)	(60,304,548.89)	(61,609,475.93)	(62,914,402.97)

Income Statement	2010	2011	2012	2012	2013	2014	2015	2016
13 2002/Decision 67744 (4/1/2005)								
14 TY 9/30/2005 (7/1/2007)								
15 TY 12/31/2006 (10/1/2009)	1,304,927.04	1,304,927.04	652,463.52					
15 TY 12/31/2010 (7/1/2012)	-	-		2,367,233.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00
16 Total	1,304,927.04	1,304,927.04	652,463.52	2,367,233.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00
Balance Sheet								
Account 1823 - Regulatory Asset (Including Escalation)								
17 Beginning Balance	8,816,064.84	31,760,945.80	32,855,525.76	32,203,062.24	32,295,324.24	30,081,840.24	27,931,380.24	25,845,521.24
18 Debit	24,249,808.00	2,399,507.00	-	2,459,495.00	2,520,982.00	2,584,006.00	2,648,607.00	2,714,822.00
19 Credit	(1,304,927.04)	(1,304,927.04)	(652,463.52)	(2,367,233.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)
20 Ending Balance	31,760,945.80	32,855,525.76	32,203,062.24	32,295,324.24	30,081,840.24	27,931,380.24	25,845,521.24	23,825,877.24
Account 2530/2540 - Liability/Regulatory Liability								
21 Beginning Balance	(71,730,467.81)	(95,980,275.81)	(98,379,782.81)	(98,379,782.81)	(100,839,277.81)	(103,360,259.81)	(105,944,265.81)	(108,592,872.81)
22 Debit	-	-	-	-	-	-	-	-
23 Credit	(24,249,808.00)	(2,399,507.00)	-	(2,459,495.00)	(2,520,982.00)	(2,584,006.00)	(2,648,607.00)	(2,714,822.00)
24 Ending Balance	(95,980,275.81)	(98,379,782.81)	(98,379,782.81)	(100,839,277.81)	(103,360,259.81)	(105,944,265.81)	(108,592,872.81)	(111,307,694.81)
Net Balance Sheet	(64,219,330.01)	(65,524,257.05)	(66,176,720.57)	(68,543,953.57)	(73,278,419.57)	(78,012,885.57)	(82,747,351.57)	(87,481,817.57)

B1

Four Corners Coal Reclamation
Projected Balances in Regulatory Asset and Coal Reclamation Liability
STF 25.15 e

Income Statement	2017	2018	2019	2020	2021	2022	2023	2024
13 2002/Decision 67744 (4/1/2005)								
14 TY 9/30/2005 (7/1/2007)								
15 TY 12/31/2006 (10/1/2009)								
15 TY 12/31/2010 (7/1/2012)	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00
16 Total	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00
Balance Sheet								
Account 1823 - Regulatory Asset (Including Escalation)								
17 Beginning Balance	23,825,877.24	21,874,103.24	19,991,897.24	18,180,997.24	16,443,186.24	14,780,292.24	13,194,187.24	11,686,791.24
18 Debit	2,782,692.00	2,852,260.00	2,923,566.00	2,996,655.00	3,071,572.00	3,148,361.00	3,227,070.00	3,307,747.00
19 Credit	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)
20 Ending Balance	21,874,103.24	19,991,897.24	18,180,997.24	16,443,186.24	14,780,292.24	13,194,187.24	11,686,791.24	10,260,072.24
Account 2530/2540 - Liability/Regulatory Liability								
21 Beginning Balance	(111,307,694.81)	(114,090,386.81)	(116,942,646.81)	(119,866,212.81)	(122,862,867.81)	(125,934,439.81)	(129,082,800.81)	(132,309,870.81)
22 Debit	-	-	-	-	-	-	-	-
23 Credit	(2,782,692.00)	(2,852,260.00)	(2,923,566.00)	(2,996,655.00)	(3,071,572.00)	(3,148,361.00)	(3,227,070.00)	(3,307,747.00)
24 Ending Balance	(114,090,386.81)	(116,942,646.81)	(119,866,212.81)	(122,862,867.81)	(125,934,439.81)	(129,082,800.81)	(132,309,870.81)	(135,617,617.81)
Net Balance Sheet	(92,216,283.57)	(96,950,749.57)	(101,685,215.57)	(106,419,681.57)	(111,154,147.57)	(115,888,613.57)	(120,623,079.57)	(125,357,545.57)

Income Statement	2025	2026	2027	2028	2029	2030	2031	2032
13 2002/Decision 67744 (4/1/2005)								
14 TY 9/30/2005 (7/1/2007)								
15 TY 12/31/2006 (10/1/2009)								
15 TY 12/31/2010 (7/1/2012)	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00
16 Total	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00
Balance Sheet								
Account 1823 - Regulatory Asset (Including Escalation)								
17 Beginning Balance	10,260,072.24	8,916,046.24	7,656,781.24	6,484,396.24	5,401,064.24	4,409,010.24	3,510,516.24	2,707,921.24
18 Debit	3,390,440.00	3,475,201.00	3,562,081.00	3,651,134.00	3,742,412.00	3,835,972.00	3,931,871.00	4,030,168.00
19 Credit	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)
20 Ending Balance	8,916,046.24	7,656,781.24	6,484,396.24	5,401,064.24	4,409,010.24	3,510,516.24	2,707,921.24	2,003,623.24
Account 2530/2540 - Liability/Regulatory Liability								
21 Beginning Balance	(135,617,617.81)	(139,008,057.81)	(142,483,258.81)	(146,045,339.81)	(149,696,473.81)	(153,438,885.81)	(157,274,857.81)	(161,206,728.81)
22 Debit	-	-	-	-	-	-	-	-
23 Credit	(3,390,440.00)	(3,475,201.00)	(3,562,081.00)	(3,651,134.00)	(3,742,412.00)	(3,835,972.00)	(3,931,871.00)	(4,030,168.00)
24 Ending Balance	(139,008,057.81)	(142,483,258.81)	(146,045,339.81)	(149,696,473.81)	(153,438,885.81)	(157,274,857.81)	(161,206,728.81)	(165,236,896.81)

Four Corners Coal Reclamation
Projected Balances in Regulatory Asset and Coal Reclamation Liability
STF 25.15 e

Net Balance Sheet	(130,092,011.57)	(134,826,477.57)	(139,560,943.57)	(144,295,409.57)	(149,029,875.57)	(153,764,341.57)	(158,498,807.57)	(163,233,273.57)

Four Corners Coal Reclamation
Projected Balances in Regulatory Asset and Coal Reclamation Liability
STF 25.15 e

Income Statement	2033	2034	2035	2036	2037	2038
13 2002/Decision 67744 (4/1/2005)						
14 TY 9/30/2005 (7/1/2007)						
15 TY 12/31/2006 (10/1/2009)						
15 TY 12/31/2010 (7/1/2012)	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	2,367,232.24
16 Total	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	4,734,466.00	2,367,232.24
Balance Sheet						
Account 1823 - Regulatory Asset (Including Escalation)						
17 Beginning Balance	2,003,623.24	1,400,079.24	899,809.24	505,393.24	219,479.24	44,778.24
18 Debit	4,130,922.00	4,234,196.00	4,340,050.00	4,448,552.00	4,559,765.00	2,322,454.00
19 Credit	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(4,734,466.00)	(2,367,232.24)
20 Ending Balance	1,400,079.24	899,809.24	505,393.24	219,479.24	44,778.24	0.00
Account 2530/2540 - Liability/Regulatory Liability						
21 Beginning Balance	(165,236,896.81)	(169,367,818.81)	(173,602,014.81)	(177,942,064.81)	(182,390,616.81)	(186,950,381.81)
22 Debit	-	-	-	-	-	-
23 Credit	(4,130,922.00)	(4,234,196.00)	(4,340,050.00)	(4,448,552.00)	(4,559,765.00)	(2,322,454.00)
24 Ending Balance	(169,367,818.81)	(173,602,014.81)	(177,942,064.81)	(182,390,616.81)	(186,950,381.81)	(189,272,835.81)
						A1
Net Balance Sheet	(167,967,739.57)	(172,702,205.57)	(177,436,671.57)	(182,171,137.57)	(186,905,603.57)	(189,272,835.81)

Four Corners Coal Reclamation
Historical Cost Summary
1/1/07 - 12/31/10
STF 25.15 e

Four Corner Coal Reclamation Expense
Charge # 99-501-013

	2007	**2008**	**2009**	**2010**
January	53,070.42	108,744.00	108,744.00	108,744.00
February	53,070.42	108,744.00	108,744.00	108,744.00
March	53,070.42	108,744.00	108,744.00	108,744.00
April	53,070.42	108,744.00	108,744.00	108,744.00
May	53,070.42	108,744.00	108,744.00	108,744.00
June	53,070.42	108,744.00	108,744.00	108,744.00
July	108,744.00	108,744.00	108,744.00	108,744.00
August	108,744.00	108,744.00	108,744.00	108,744.00
September	108,744.00	108,744.00	108,744.00	108,744.00
October	108,744.00	108,744.00	108,744.00	108,744.00
November	108,744.00	108,744.00	108,744.00	108,744.00
December	108,744.00	108,744.00	108,744.00	108,744.00
Total	970,886.52	1,304,928.00	1,304,928.00	1,304,928.00
				A1

Consumer Price Index - All Urban Consumers
12-Month Percent Change

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100
Years: 2000 to 2010

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2000	2.7	3.2	3.8	3.1	3.2	3.7	3.7	3.4	3.5	3.4	3.4	3.4	3.4
2001	3.7	3.5	2.9	3.3	3.6	3.2	2.7	2.7	2.6	2.1	1.9	1.6	2.8
2002	1.1	1.1	1.5	1.6	1.2	1.1	1.5	1.8	1.5	2.0	2.2	2.4	1.6
2003	2.6	3.0	3.0	2.2	2.1	2.1	2.1	2.2	2.3	2.0	1.8	1.9	2.3
2004	1.9	1.7	1.7	2.3	3.1	3.3	3.0	2.7	2.5	3.2	3.5	3.3	2.7
2005	3.0	3.0	3.1	3.5	2.8	2.5	3.2	3.6	4.7	4.3	3.5	3.4	3.4
2006	4.0	3.6	3.4	3.5	4.2	4.3	4.1	3.8	2.1	1.3	2.0	2.5	3.2
2007	2.1	2.4	2.8	2.6	2.7	2.7	2.4	2.0	2.8	3.5	4.3	4.1	2.8
2008	4.3	4.0	4.0	3.9	4.2	5.0	5.6	5.4	4.9	3.7	1.1	0.1	3.8
2009	0.0	0.2	-0.4	-0.7	-1.3	-1.4	-2.1	-1.5	-1.3	-0.2	1.8	2.7	-0.4
2010	2.6	2.1	2.3	2.2	2.0	1.1	1.2	1.1	1.1	1.2	1.1	1.5	1.6
										11 Year Average CPI:			**2.5**

Source: Bureau of Labor Statistics Data
http://data.bls.gov/pdq/SurveyOutputServlet