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August 8, 2013

HAND DELIVERED

Ms. Ann Cole, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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Re: Petition for Rate Increase by Tampa Electric Company
FPSC Docket No. 130040-EI

Dear Ms. Cole:

Enclosed for filing in the above docket, on behalf of Tampa Electric Company, are the original and twenty (20) copies of each of the following:

1. Rebuttal Testimony and Exhibit of Sandra W. Callahan
2. Rebuttal Testimony and Exhibit of Robert B. Hevert
3. Rebuttal Testimony and Exhibit of Lorraine L. Cifuentes
4. Rebuttal Testimony and Exhibit of Mark J. Hornick
5. Rebuttal Testimony and Exhibit of S. Beth Young
6. Rebuttal Testimony and Exhibit of Brad J. Register
7. Rebuttal Testimony of Steve P. Harris
8. Rebuttal Testimony of Edsel L. Carlson
9. Rebuttal Testimony of Jeffrey S. Chronister
10. Rebuttal Testimony and Exhibit of William R. Ashburn
11. Rebuttal Testimony and Exhibit of Karen J. Lewis
12 Rebuttal Testimony and Exhibit of Terry Deason

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

COM 5
AFD 3
APA 3
ECO 5+CD
ENG
GCL 3
IDM
TEL
CLK 1 (ctrep)

JDB/pp
Enclosures

cc: All Parties of Record (w/encls.)

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT
OF
SANDRA W. CALLAHAN

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BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

SANDRA W. CALLAHAN

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

A. My name is Sandra W. Callahan. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am Vice President and Chief Financial Officer of Tampa Electric Company ("Tampa Electric" or "company") and Senior Vice President and Chief Financial Officer of TECO Energy ("TECO Energy" or "Parent Company").

Q. Are you the same Sandra W. Callahan who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address issues in the prepared direct testimony of witnesses Kevin W. O'Donnell, testifying on behalf of the Office

of Public Counsel ("OPC"), Richard A. Baudino and Lane Kollen, testifying on behalf of the WCF Hospital Utility Alliance ("HUA"), and Mike Gorman, testifying on behalf of the Federal Executive Agencies ("FEA").

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes, I have. My Exhibit No. ___ (SWC-2) consists of one document that was prepared under my direction and supervision and is entitled "Tampa Electric 2008 to 2014 Regulated Capital Structure Including ADIT".

Q. Please summarize the key concerns and disagreements you have regarding the substance of the various witnesses' testimony.

A. My key concerns and disagreements are with the following matters:

- Witness O'Donnell's and witness Gorman's claim that OPC's and FEA's recommendations in this case will result in financial parameters that rating agencies associate with strong financial integrity and will result in Tampa Electric maintaining its current credit ratings;

- Witness O'Donnell's proposal that the company's capital structure requested in this case should be modified to 50.0 percent common equity, 49.21 percent long-term debt and 0.79 percent short term debt;
- Witness O'Donnell's and witness Baudino's characterization of the changes in the company's equity ratio since its last rate case;
- Witness O'Donnell's claim that TECO Energy is using "double leverage" to subsidize its unregulated operations and that the Commission should consider the consolidated capital structure in setting rates; and
- Witness Kollen's proposed incentive mechanism to reduce Tampa Electric's common equity ratio.

FINANCIAL INTEGRITY

Q. Witness O'Donnell and witness Gorman claim that their recommendations in this case will result in financial parameters that rating agencies associate with strong financial integrity and that will allow the company to maintain its' current credit ratings. Do you agree?

A. No. Both witnesses discuss substantial reductions to the company's proposed rate increase (and even a rate decrease) and resulting estimates of credit metrics that

the witnesses improperly assert are consistent with Tampa Electric's current credit ratings. Witness Gorman's are based on a fundamentally flawed capital structure allocation, as addressed by Tampa Electric rebuttal witness Jeffrey S. Chronister, and are calculated in a manner inconsistent with methods used by the rating agencies and therefore, produce results that would be meaningless to a ratings analyst.

Witness O'Donnell did not provide the calculations of his credit metrics. However, comparing his results to credit metrics reflected in Document 4 of my Exhibit No. ___ (SWC-1) of my Direct Testimony in this case shows that his metrics were also not calculated in accordance with the rating agencies methodology and should be rejected.

Q. Please explain further.

A. In Document 4 of my Exhibit No. ___ (SWC-1) of my Direct Testimony in this case, I calculated and showed what Tampa Electric's credit metrics would be in 2014 if the company does not obtain any rate relief in this case. The resulting metrics, which were prepared consistent with the method used by Standard & Poors ("S&P"), show a

sharp deterioration from metric levels achieved over the last several years to lower levels that likely will not support the company's current credit ratings. The metrics shown in my exhibit are significantly lower than the corresponding amounts presented by witness O'Donnell, even though his metrics purportedly assume a revenue reduction of $5.6 million and higher levels of debt. Based on Document 4 of my Exhibit No. ___ (SWC-1) of my Direct Testimony in this case and absent supporting calculations from witness O'Donnell, his statements that a revenue decrease of $5.6 million as proposed by OPC will allow the company to maintain its current ratings should be rejected as unsupported.

Q. What other reactions will the rating agencies likely have if the commission adopts the recommendations of OPC and FEA in this case?

A. In addition to the sharp decline in credit metrics, the most important factor that the witnesses fail to consider is what the rating agencies' reactions would be to a Commission decision that is not credit-supportive or is inconsistent with previous Commission decisions. For instance, the return on equity ("ROE") percentages proposed by OPC and FEA are 200 to 225 basis points

below the company's request and 125 to 150 basis points below the Commission's most recent ROE decision in the Florida Power & Light ("FPL") case. Taking into account that interest rates have actually increased between 70 and 80 basis points since the FPL case was decided, for the Commission to adopt OPC or FEA's proposed ROEs would be viewed as highly inconsistent and a dramatic reversal of the Commission's history of decisions that are supportive of financially healthy utilities in Florida. The impact of this inconsistent and non-credit supportive decision would be even more damaging than the sharp decline in credit metrics as the agencies reassess the increased business risk associated with a perceived change in the regulatory environment.

Q. Do you agree with the assertions of witnesses O'Donnell and Gorman that Tampa Electric could maintain its current credit ratings if the Commission adopted the recommendations of OPC and FEA?

A. No. Tampa Electric currently has a "stable outlook" on its credit ratings. This means that a rating agency does not anticipate a change in a company's ratings over the next 12 to 24 months. The stable outlooks from the three rating agencies reflect their views that credit

metrics will remain supportive of current ratings over the foreseeable future, that the regulatory environment in Florida will remain supportive, and that Tampa Electric will likely receive a fair and balanced decision in this case that is consistent with other recent rate decisions in Florida. If the Commission adopts the recommendations of the OPC and FEA, clearly none of these expectations will be met. A Commission decision considered to be unsupportive of financial integrity at a time when Tampa Electric is entering a period of a significant capital spending will likely result in ratings downgrades.

Q. How would a rating downgrade impact Tampa Electric and its customers?

A. A rating downgrade would likely increase the interest rates Tampa Electric would need to agree to pay when issuing long-term debt. Over a 30 year maturity period, even small increases in interest rates matter. Of course, the impact of a credit downgrade on the company's long-term interest rates would be only part of the negative impact. Tampa Electric spends millions of dollars each year on commodities like fuel, on large and complicated pieces of machinery and equipment and on

services like transportation. Market perceptions of Tampa Electric's creditworthiness impact the willingness of counterparties and vendors to extend credit to the company as well as the terms on which credit is granted. Likewise, it was not too many years ago that the markets were disrupted and only the most creditworthy companies had ready access to the capital markets. The time to have a strong credit rating is before economic and market disruptions or other unforeseen events occur, not after, because by then it will be too late.

Q. Witness O'Donnell claims that Tampa Electric's credit ratings are lower than they would be as a stand-alone company, and that its ratepayers are subjected to incrementally higher interest rates as a result. Is he correct?

A. No. Witness O'Donnell apparently draws that false conclusion based on his incorrect belief that all ratings of Tampa Electric are based on the consolidated financial profile of TECO Energy. The fact that he incorrectly identifies Tampa Electric's rating from Moody's Investor Service ("Moody's") as Baa2, when Baa2 is actually TECO Energy's rating, is simple proof that he is confused and his conclusion is incorrect. Tampa

Electric's rating is two notches higher at A3, which shows that rating agencies can and do look at Tampa Electric's credit on a specific company basis.

His assertion that credit rating agencies look to the consolidated TECO Energy risk and credit profile when setting the credit ratings for the utility is not correct. Moody's and Fitch Ratings ("Fitch") evaluate Tampa Electric on its stand-alone credit metrics and business risk profile to determine the credit profile and rating for the regulated business. Tampa Electric's unsecured credit ratings from Moody's and Fitch are A3 and A-, respectively, while the unsecured ratings of TECO Energy are Baa2 and BBB, respectively. Only S&P uses a consolidated method in establishing the credit ratings of the utility, and thus, the S&P ratings of Tampa Electric (BBB+) and TECO Energy (BBB) are more closely linked.

Based on our experience pricing debt issuances, debt investors clearly understand the methodology difference and tend to discount the one notch difference in the S&P rating. We know this because Tampa Electric's debt prices are more in line with the A3/A- ratings that Moody's/ Fitch assign to Tampa Electric than with the

BBB+ rating assigned by S&P. To illustrate, the credit spreads on Tampa Electric's 4.10 percent bonds issued in 2012 and due 2042 have traded in line with "A" rated peers in 2013.

CAPITAL STRUCTURE

Q. Do you agree with witness O'Donnell's recommendation that the Commission approve an equity ratio of 50 percent for Tampa Electric?

A. No. The Commission in Tampa Electric's last base rate proceeding authorized an equity ratio of 53.96 percent. This credit-supportive Commission decision in 2009 has contributed to Tampa Electric achieving strong credit metrics, much needed credit rating upgrades, stable ratings outlooks, and unimpeded access to capital at very competitive rates, which customers have benefited from. The company's actual equity ratio is at the approved 54 percent. Absent a compelling reason, which witness O'Donnell fails to provide, the Commission should not reverse its support of Tampa Electric's financial integrity and require a reduction in the company's existing and requested equity ratio of 54.2 percent.

Q. Please provide a brief summary of witness O'Donnell's recommendation as it relates to the company's capital structure.

A. Witness O'Donnell recommends that the Commission adopt a capital structure that is comprised of 50.0 percent equity, 49.21 percent long-term debt and 0.79 percent short-term debt. Witness O'Donnell arrives at his recommendation based upon a premise that a capital structure more reflective of the TECO Energy consolidated capital structure is appropriate for setting rates based on his assertion that there is clear evidence of "double leverage." He also provides a calculation of the average common equity ratios granted by state regulators from 2010 through 2012 and for 2013 to-date, calculated by witness O'Donnell to be 49.19 percent and 49.64 percent, respectively, as support for his recommendation.

Q. What role does the notion of "double leverage" play in witness O'Donnell's conclusion regarding the use of TECO Energy's consolidated capital structure for guidance in establishing the equity ratio for Tampa Electric?

A. Witness O'Donnell suggests that because there is more

debt at the consolidated level than at Tampa Electric, the subsidiary's equity includes a mixture of both debt and equity. To reflect this so-called "double leverage", witness O'Donnell is recommending that the consolidated capital structure be considered in setting rates in this case.

Q. Do you agree with witness O'Donnell's position that the capital structure should be adjusted to reflect the presumed effect of double leverage?

A. No. Witness O'Donnell's approach is contrary to the Commission's longstanding practice. He fails to substantiate his claim that TECO Energy used debt to fund equity infusions to Tampa Electric. His argument of "double leverage" is unsubstantiated and it is inconsistent with sound regulatory theory and precedent. Additionally, his recommendation to use the consolidated capital structure is inconsistent with the widely accepted practice of using the actual capital structures of the utility operating companies. This approach is referred to as the "Stand-Alone Approach". The Alberta Energy and Utilities Board described the stand-alone principle as follows:

"This first application of the stand-alone principle is designed to remove the effects of diversification by utilities into non-regulated activities. Using the stand-alone principle in this case, a utility is regulated as if the provision of the regulated service were the only activity in which the company is engaged. This application of the principle is not influenced up or down by the operations of a parent or "sister" company. Thus, the cost (or revenue requirement) of providing utility service reflects the expenses, capital costs, risks and required returns associated with the provision of the regulated service." (Alberta Energy and Utilities Board, Decision 2001-92, December 12, 2001, at page 25)

Q. Are there other examples where the use of double leverage has been rejected?

A. Yes, there are many other cases where double leverage has been rejected based on the concept of a stand-alone approach. For example, FERC's position on the use of double leverage is as follows:

"The FERC does not embrace the concept of double

leverage. For purposes of calculating rate of return for wholly owned subsidiaries, FERC uses the stand-alone capital structure and return on equity of the subsidiary so long as the subsidiary issues its own debt, maintains its own credit ratings and meets other standards related to equity ratio. The courts have upheld this policy." *See Missouri Pub. Serv. Comm'n v. Federal Energy Reg Comm'n, 215 F.3d 1, 342 U.S.App. D.C.(D.C. Cir. June 27, 2000)*

Q. How does this concept apply to the use of TECO Energy's consolidated capital structure for purposes of setting rates for the utility?

A. It is a classic example of what FERC and others who have applied the stand-alone approach were attempting to avoid and that is using consolidated parameters in setting rates such that the unregulated operations of a holding company negatively impact the utility.

TECO Energy's consolidated capital structure does contain more debt than the utilities' capital structure for reasons I explain below. However, if the Commission accepts witness O'Donnell's recommendation to use the consolidated capital structure which has higher

leverage, that would be harmful to Tampa Electric's credit rating and the concept of protecting the regulated operations from unregulated activity would be compromised. This supports the long standing position of this Commission and other regulatory jurisdictions to embrace the stand-alone concept and avoid any application of a double leverage adjustment.

Q. Did witness O'Donnell support his claim that TECO Energy is using debt proceeds to finance equity contributions to Tampa Electric?

A. No. He relies on his exhibit KWO-3 which compares the total of the common equity balances of Tampa Electric, Peoples Gas System ("PGS") and TECO Energy's unregulated businesses to TECO Energy's consolidated equity and exhibit KWO-5 which is a comparison of the capital structures of those businesses to support his conclusion that TECO Energy is using debt proceeds to finance equity contributions to Tampa Electric. TECO Energy's consolidated capital structure does contain more debt than the utilities' capital structures. However, this is a direct result of an investment in an unregulated merchant power business more than ten years ago that was initially funded with a balanced capital approach.

However, the investment failed and substantial losses were sustained, effectively eliminating the equity capital supporting the investment, while the debt remained. The result was a levered position that ultimately caused the rating agencies to lower TECO Energy's credit ratings to below investment grade. Over time, this debt has been reduced substantially and the investment grade ratings have been reinstated. Although it is usually impossible to "trace funds", in this case, the non-utility debt in the TECO Energy capital structure clearly relates to TECO Energy's failed investment in merchant power and does not support the equity of Tampa Electric.

Q. Do you agree that witness O'Donnell's calculation of approved equity ratios in other regulatory jurisdictions is an appropriate proxy for the company's requested 54.2 percent?

A. No. Witness O'Donnell's exhibit KWO-7 includes a history of decisions from around the country from 2010 to 2012 that comprise the average 49.19 percent equity ratio he uses as a comparison. However, this exhibit contains lower equity ratios computed using other items of capital beyond investor sources, primarily

Accumulated Deferred Income Taxes ("ADIT"). Although I did not investigate every entry in his exhibit, I did determine that the results included in the exhibit for the Florida, Michigan, Indiana and Arkansas jurisdictions that are in the 40 percent range are calculated using other sources of capital, not just investor sources. These lower equity ratios are not comparable to Tampa Electric's requested 54.2 percent equity ratio, which is calculated only using investor sources of capital. Hence, witness O'Donnell's calculation of an overall 49.19 percent average equity ratio is not comparable to the 54.2 percent requested equity ratio and should be rejected.

Q. Witness O'Donnell alleges that TECO Energy can "lean on Tampa Electric" to take cash withdrawals to sustain operations in its non-regulated companies, pointing to the varying level of dividends that have been paid as presented in KWO-6. Does KWO-6 support witness O'Donnell's premise that the Commission should look to TECO Energy's capital structure in setting a capital structure for Tampa Electric?

A. No. There is no basis for witness O'Donnell's claim that TECO Energy "leaned on" Tampa Electric to support

its unregulated operations and, in fact, the opposite is true. The "cash withdrawals" that witness O'Donnell refers to are actually Tampa Electric's dividend payments to its parent company, TECO Energy. These dividend payments were based on a consistent dividend policy which has been in effect since the holding company was formed in 1981. This dividend policy, which applies to all operating companies, provides for a quarterly dividend tied to the level of net income achieved during the quarter. Any variation in amount is simply a reflection of a variation in net income. Separately, TECO Energy infuses equity into Tampa Electric as needed to meet external funding needs and maintain an appropriate capital structure. From 2006 to 2012, TECO Energy infused $573 million of equity into Tampa Electric. During that same period, TECO Energy's unregulated businesses returned $686 million of cash to the parent company in excess of dividends. Far from TECO Energy being able to "lean on Tampa Electric," it is Tampa Electric that is able to lean on TECO Energy when its investment needs exceed its internal cash generation.

Q. Please describe how witness O'Donnell and witness Baudino characterize the changes in the company's equity

ratio since the last base rate proceeding in 2008.

A. Witnesses O'Donnell and Baudino assert or imply that equity infusions were increased in 2012 to achieve a 54 percent equity ratio based only on the timing of Tampa Electric's base rate filing.

Q. Are their assertions correct?

A. No. The timing of the equity contributions was not, as asserted by witnesses Baudino and O'Donnell, influenced by the timing of Tampa Electric's base rate proceeding. As I stated on page 26 of my direct testimony, bonus depreciation and additional tax deductions for repairs provided $350 million of unanticipated cash benefits to Tampa Electric which displaced and delayed the company's anticipated need for equity infusions. These cash tax benefits added a substantial amount of zero cost capital to Tampa Electric's regulatory capital structure, reduced the weighted cost of capital by almost one percent, and helped delay the need for rate relief. It was not until 2012, when Tampa Electric had significant debt maturities which increased its need for external capital, that it had the opportunity to replace debt with equity and increase its equity ratio to 54 percent.

Q. Is there any additional support that you can provide that will illustrate how these tax benefits offset the necessity for other capital since the last base rate proceeding?

A. Yes. Using the regulated system per books capital structures as reported on the company's Surveillance Report, Document No. 1 of my exhibit shows the percentage that each source of capital represents in the overall capital structure from 2008 to 2014. The sources of capital include ADIT. As demonstrated in Document No. 1 of my exhibit, the ratio of ADIT increases 9.2 percent during this timeframe while long-term debt declines 7.1 percent and common equity declines 2.2 percent. This equates to an increase in ADIT of $0.6 billion, representing 50 percent of the overall $1.2 billion increase in total capital. The fact that ADIT provided half of the capital required reflects the magnitude of the unanticipated funding provided by the additional tax benefits after the company's last base rate proceeding and shows why the company relied on zero cost capital from deferred taxes before adding more expensive equity capital.

Q. Does the company expect similar levels of tax benefits

from additional bonus depreciation or tax repairs to occur in the future?

A. No. While the company and customers benefited from what amounted to an additional and unprecedented interest-free source of cash, the company does not expect benefits of that magnitude to continue. The bonus depreciation enacted in the Economic Stimulus Act of 2008 has been extended by a series of economic stimulus legislation for six years now. This six-year period of stimulus has lasted twice as long as any prior bonus depreciation legislation. Also, the bonus allowance, at 50 percent and 100 percent, has been significantly more generous than any prior bonus depreciation legislation. Recent improvements in the economy have reduced the need for stimulus, and current congressional committee discussions of corporate tax reform have considered reducing preference items such as accelerated depreciation. Against this backdrop, it seems unlikely that bonus depreciation will be extended beyond the already unprecedented levels. While tax repair deductions will occur on an annual basis and provide an annual cash benefit of approximately $35 million, the benefit of the 10-year "lookback" provided a significant one-time cash benefit of $127 million and will not

reoccur.

The likelihood that future federal tax policy will not be yielding additional significant opportunities to increase the amount of zero cost deferred taxes in our capital structure is but another reason why the Commission should approve the company's requested equity ratio in this case.

Q. Do you believe the option proposed by witness Kollen to incentivize the company to reduce its common equity ratio is appropriate?

A. No, I do not. As I have testified, I believe that Tampa Electric's current equity ratio is an important element of its financial strength. The goal of incentive compensation should be to incent achievements that are beneficial - such as safety, reliability, and financial performance. It strikes me as counterproductive and very poor policy to provide incentives to do something that is clearly not good for the company. Rebuttal witness Terry Deason discusses this point further in his testimony on behalf of Tampa Electric Company.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony has addressed the primary concerns and disagreements I have regarding the testimony of the interveners' witnesses O'Donnell, Baudino and Gorman regarding Tampa Electric's capital structure and financial integrity. The most important elements of their testimonies that my rebuttal shows to be incorrect and unsupported are witnesses' assertions that intervener recommendations would allow Tampa Electric to maintain its current credit ratings, assertions about double leverage, and characterizations of the timing of equity contributions. The Commission's credit supportive decisions in Tampa Electric's last base rate proceeding allowed the company to achieve needed improvements to its financial integrity and credit ratings. The witnesses have provided no compelling reasons for the Commission to take actions that would diminish Tampa Electric's existing financial integrity and credit ratings.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
FILED: 08/08/2013

EXHIBIT

OF

SANDRA W. CALLAHAN

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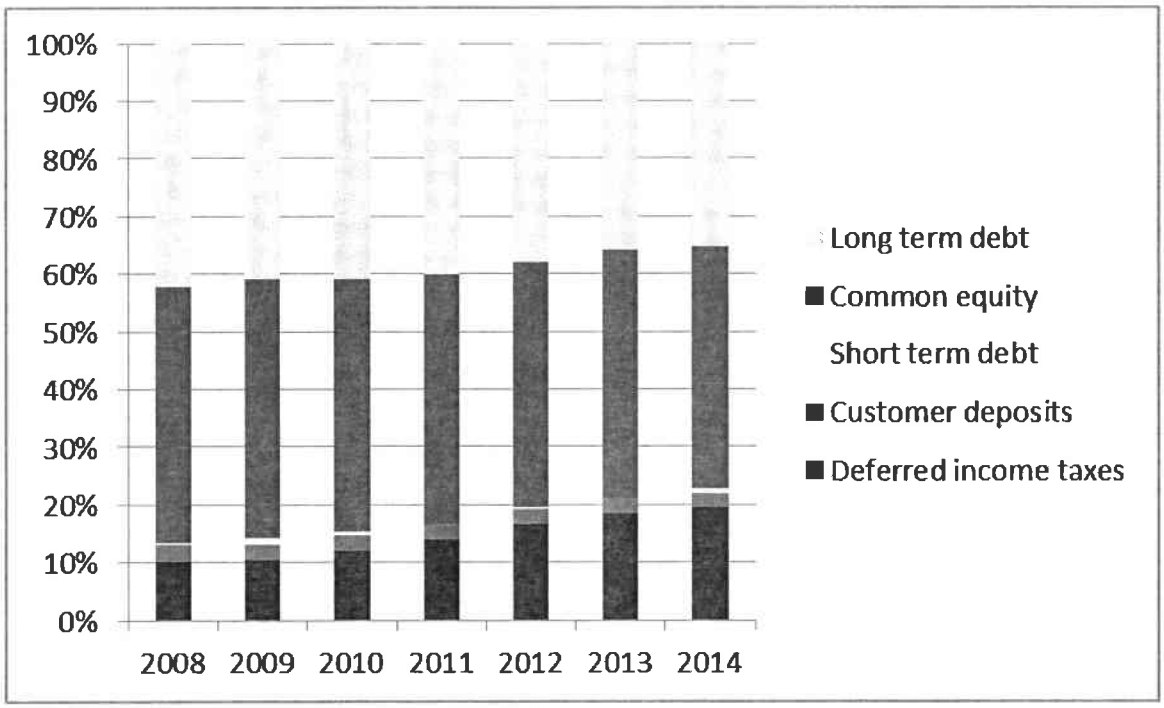
TAMPA ELECTRIC - 2008 TO 2014

REGULATED CAPITAL STRUCTURE INCLUDING ADIT



BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION FOR AN INCREASE IN BASE RATES

AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT

OF

ROBERT B. HEVERT

ON BEHALF OF TAMPA ELECTRIC COMPANY

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

ROBERT B. HEVERT

ON BEHALF OF TAMPA ELECTRIC COMPANY

I. INTRODUCTION

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

A. My name is Robert B. Hevert. I am Managing Partner of Sussex Economic Advisors, LLC ("Sussex"). My business address is 161 Worcester Road, Suite 503, Framingham, Massachusetts 01701.

Q. Are you the same Robert B. Hevert who filed direct testimony in this proceeding?

A. Yes I am.

Q. Please state the purpose of your rebuttal testimony.

A. The purpose of my rebuttal testimony is to respond to the direct testimony of witness Michael P. Gorman on behalf of the Federal Executive Agencies ("FEA"); witness Richard A. Baudino on behalf of the WCF Hospital Utility

Alliance ("HUA"); witness Dr. J. Randall Woolridge on behalf of the Florida Office of Public Counsel ("OPC"); and witness Steve W. Chriss on behalf of the Florida Retail Federation ("FRF") (together "opposing ROE witnesses") as their testimony relates to the Company's Return on Equity ("ROE" or "Cost of Equity"). I also respond to OPC witness Kevin W. O'Donnell's direct testimony regarding the Company's capital structure.

II. SUMMARY AND OVERVIEW

Q. Please summarize the key issues and recommendations addressed in your rebuttal testimony.

A. In my direct testimony, I recommended an ROE range of 10.50 percent to 11.50 percent and within that range, recommended a return of 11.24 percent. The updated analyses contained in my rebuttal testimony continue to support that range and recommendation. As my direct testimony noted, and as discussed throughout my rebuttal testimony, my recommendations and the analytical results on which they are based, consider a variety of analytical results, and reflect a number of factors including prevailing and expected capital market conditions. Doing so is especially important when conditions have changed significantly over a relatively brief period, as recently

has been the case.

In this proceeding, there is a meaningful difference in the ranges and recommendations offered by the various ROE witnesses. As my rebuttal testimony demonstrates, there are a number of methodological, theoretical and practical reasons why ROE recommendations as low as 8.75 percent in the case of witness Woolridge, or 9.30 percent in the case of witness Baudino are unreasonably low. Certain of the opposing ROE witnesses, for example, develop their recommendations by giving weight to ROE estimates that are well below any return authorized by any regulatory commission in at least 30 years. Despite the significant effect of those estimates on their ROE ranges and recommendations, and notwithstanding the fact that those results are so low as to be highly improbable relative to observed authorized returns, none of those witnesses has explained why Tampa Electric is so less risky, or how it is that present capital market conditions are so benign that investors would reduce their return requirements far below the returns available to other vertically integrated utilities.

In addition, there is a relatively recent and highly relevant benchmark by which ROE recommendations in this

proceeding can be assessed: the 10.50 percent ROE authorized for Florida Power and Light ("FP&L") by the Commission in Docket No. 120015-EI.[1] While my recommended range (10.50 percent to 11.50 percent) coincides with that return, the opposing ROE witnesses have recommended ROE ranges that are substantially and unreasonably below the Commission's decision. At issue, then, is whether there is a reasonable basis to conclude that the return required by equity investors for a vertically integrated electric utility such as Tampa Electric has fallen by 120 basis points or more since December 2012.[2] That is especially the case since visible measures of investor return requirements, such as long-term interest rates, have increased over that period.

Q. Please expand on that last point.

A. There is little question that both current and expected long-term interest rates have increased since the Commission's decision in the FP&L proceeding. On a spot basis, the 30-year Treasury yield rose by 78 basis points from December 12, 2012 through July 31, 2013. Similarly, the Moody's A and Baa-rated Utility Bond Indices increased by 82 basis points and 78 basis points, respectively, over the same period (*see* Document No. 7 of

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1 Florida Public Service Commission, Docket No. 120015-EI, Order No. PSC-13-0023-S-EI, at 5.

2 Refers to the date on which the revised Stipulation and Settlement containing the 10.50 percent ROE was filed in Docket No. 120015-EI. *See* Order No. Order No. PSC-13-0023-S-EI, at 8. Please also see Document No. 40 of my exhibit, which notes that Regulatory Research Associates reports the decision date in that docket as December 13, 2013.

my exhibit). On a forward-looking basis, the expected 27-year Treasury yield three years hence (that is, the "forward" 27-year Treasury yield discussed below; *see* also Document 8 of my exhibit) increased by 79 basis points.

It also is the case that both current and forward interest rates have increased since the date of the analyses contained in my direct testimony (i.e., February 15, 2013). On a spot basis, the Treasury yield curve has shifted upward, with longer-term maturities experiencing the greater increases; the same holds true for forward long-term Treasury yields. Even over a more recent period, (*i.e.*, from May 1, 2013 to July 12, 2013) forward long-term Treasury yields increased by 86 basis points.[3]

Q. Is it also the case that utility dividend yields recently have increased?

A. Yes, it is. Similar to my review of interest rates, I calculated the average dividend yield for my proxy group from May 1, 2013 through July 12, 2013. As Document No. 9 of my exhibit indicates, the proxy group dividend yield increased by 23 basis points over that time.

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[3] Forward yields were calculated as the expected long-term Treasury yield three years forward for each trading day from February 15, 2013 through July 12, 2013. That calculation is based on the "expectations" theory, which states that (for example) the current 30-year Treasury yield equals the combination of the current three-year Treasury yield, and the 27-year Treasury yield expected in three years. That is, an investor would be indifferent to (1) holding a 30-year Treasury to maturity, or (2) holding a three-year Treasury to maturity, then a 27-year Treasury bond, also to maturity. As illustrated in Document No. 8 of my exhibit since February 15, 2013, forward yields have increased by 49 basis points. *See* Document No. 8 of my exhibit.

Q. In light of that data, what are your conclusions regarding the opposing ROE witnesses' recommendations?

A. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation, itself. While I appreciate that all analyses necessarily require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst. Because the application of financial models and interpretation of their results is often the subject of differences among analysts in regulatory proceedings, I believe that it is important to review and consider a variety of data points; doing so enables us to put in context both quantitative analyses and the associated recommendations. In my view, the broad increase in interest rates since December 2012 is a relevant data point that is difficult to reconcile with the dramatic decrease in returns recommended by the opposing ROE witnesses.

As noted in my direct testimony, it also is important to recognize that in establishing their return requirements,

investors consider a broad range of data including authorized returns from alternative jurisdictions, and current capital market data.[4] Equity investors have many options available to them, and allocate their capital based on the expected returns associated with those alternatives. While I am not suggesting that the Commission should be bound by decisions in other regulatory jurisdictions, given that investors consider such data in framing their investment decisions, return recommendations that materially deviate from observed industry norms should be supported by clear and unambiguous reasons explaining those deviations.

As discussed throughout my rebuttal testimony, there are a number of methodological, theoretical and practical reasons why recommendations as low as 8.75 percent are unreasonably low. Witness Woolridge, for example, develops his recommendation by giving weight to ROE estimates that are well below all returns authorized for vertically integrated utilities by any regulatory commission in at least 30 years.[5] Witness Baudino points to comparatively low long-term Treasury yields and concludes, by extension, that the Cost of Equity must be commensurately low.[6] As noted above, that position is at odds with observable data.

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4 *See* direct testimony and Exhibit of Robert B. Hevert at 36 - 39; 52 - 65.

5 I note that witness Dr. Woolridge's 8.75 percent DCF result is below all authorized ROEs for vertically integrated utilities since at least 1980.

6 *See* direct testimony of Richard A. Baudino, at 7.

As discussed in my direct testimony, no one financial model is any more "correct" than any other method in all circumstances, and as such, it is important to consider the results of a variety of methods.[7] That observation is especially important when market conditions are such that financial models produce results that are widely divergent and highly sensitive to inputs and assumptions. Neither market conditions in general, nor the Company's situation in particular supports the proposition that Tampa Electric's Cost of Equity is far below recently authorized returns, as several of the opposing ROE witnesses assume to be the case.[8] While their recommendations may be consistent with each other, my recommended range is consistent with a broader, highly relevant set of observations: the returns available to other electric utilities (*see* Document No. 10 of my exhibit).

III. RESPONSE TO FEA WITNESS GORMAN AS IT RELATES TO THE COMPANY'S COST OF EQUITY

Q. Please briefly summarize witness Gorman's recommendation regarding the Company's Cost of Equity.

A. Witness Gorman recommends an ROE of 9.25 percent, within a recommended range of 9.15 percent to 9.30 percent.[9] Witness Gorman establishes his ROE recommendation by

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7 *See* direct testimony and Exhibit of Robert B. Hevert, at 19-20.

8 I recognize that witness Chriss considers recently authorized returns in other jurisdictions. *See* direct testimony of Steve W. Chriss, at 10.

9 *See* direct testimony of Michael P. Gorman, at 2 and 46.

reference to his Constant Growth DCF analysis assuming analysts' earnings growth estimates (9.16 percent to 9.40 percent), his Multi-Stage DCF analysis (8.89 percent), and his Risk Premium analyses (9.30 percent).[10] Witness Gorman also considers his Sustainable Growth DCF model results (8.14 percent to 8.30 percent), although he does not place specific weight on those estimates.[11] Similarly, while he performs a CAPM analysis, witness Gorman places "minimal" weight on those results (8.60 percent).[12]

Q. What are the principal areas in which you disagree with witness Gorman?

A. The principal areas in which I disagree with witness Gorman's analyses and conclusions include: (1) the long-term growth estimate used in the Constant Growth DCF model; (2) the application of the Multi-Stage DCF model; (3) the Market Risk Premium (the "MRP") component of the CAPM and in particular, the expected market return from which the MRP is calculated; (4) the assumptions and methods underlying witness Gorman's Risk Premium analyses; and (5) the implications of current market conditions for Tampa Electric's Cost of Equity.

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10 *Ibid.*, at 34 and 40.
11 *Ibid.*, at 34-35.
12 *Ibid.*, at 46.

Application of the Constant Growth DCF Model

Q. What is the primary difference between you and witness Gorman in the application of the Constant Growth DCF model?

A. While we agree that it is appropriate to rely on analyst earnings growth estimates in applying the Constant Growth DCF model, witness Gorman reasons that those estimates should be limited to what he considers may be a reasonable estimate of long-term "sustainable" growth. In that regard, because they are higher than the five- and ten-year nominal Gross Domestic Product ("GDP") growth estimates provided by the *Blue Chip Financial Forecast* ("*Blue Chip*"), witness Gorman concludes that the mean and mean-high analyst consensus earnings growth estimates in my Constant Growth DCF analysis are irrational.[13] Aside from his focus on the *Blue Chip* forecasts, witness Gorman suggests that the growth estimates included in my analyses cannot be sustained by the proxy group companies' current earnings retention ratios.[14]

As discussed below, the salient issue in assessing growth rates in the context of the DCF model is whether investors tend to rely on a particular estimate of

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13 *Ibid.*, at 54 - 55.

14 *Ibid.*, at 55.

growth. As discussed in my response to witness Baudino, prior academic research (as well as the analyses presented later in my rebuttal testimony) indicates that, consistent with the approach used in my analyses, investors rely on analysts' earnings growth projections in valuing equity securities. While witness Gorman may be of the view that analyst growth rates are not sustainable, the relevant issue is whether investors rely on those projections in making their investment decisions. Given the empirical evidence supporting the use of analysts' earnings growth projections, I disagree with witness Gorman's conclusion that my constant growth DCF produces overstated results. I discuss witness Gorman's 4.90 percent long-term growth assumption in more detail later in this section of my rebuttal testimony.

Application of the Multi-Stage DCF Model

Q. Do you agree with witness Gorman's application of the Multi-Stage DCF model?

A. While I agree that the Multi-Stage DCF approach is a reasonable analytical technique, witness Gorman's Multi-Stage model contains several assumptions that produce unreasonably low ROE estimates. In particular, witness Gorman's model assumes a perpetual growth rate beginning

in the eleventh year of his model (that is, calendar year 2024) based on a GDP growth rate projection that actually ends in 2024. In addition, despite the fact that they are paid on a quarterly basis, witness Gorman assumes that all dividends are received at the end of the year. Those assumptions have the effect of unreasonably decreasing the DCF result.

Q. How does witness Gorman's assumption with regard to the timing of dividend payments affect his Multi-Stage DCF model results?

A. Witness Gorman notes that quarterly dividends in his Multi-Stage DCF model were "annualized (multiplied by 4)."[15] Considering that the companies within witness Gorman's proxy group pay dividends on a quarterly basis, assuming (as witness Gorman has done) that the entire dividend is paid at the end of that year essentially defers the timing of the quarterly cash flows (that is, the quarterly dividends) until year-end, even though they are paid throughout the year. Since witness Gorman's model assumes annual dividend payments, a reasonable approach would be to assume that cash flows are received (on average) in the middle of the year, such that half the quarterly dividend payments occur prior to the

15 *Ibid.*, at 25.

assumed dividend payment date, and half occur after (i.e., the "mid-year convention"). That approach is consistent with the common practice in the Constant Growth DCF model of accounting for periodic growth in dividends by applying one-half of the expected annual dividend growth rate to calculate the expected dividend yield.

Q. How would the mid-year convention affect witness Gorman's Multi-Stage DCF results?

A. Holding all other assumptions constant, simply changing witness Gorman's methodology to reflect the mid-year convention increases the mean and median results by approximately 17 basis points.[16]

Q. Do you agree with the long-term growth rate in witness Gorman's Multi-Stage DCF model?

A. No, I do not. The long-term growth rate represents the expected rate of growth, in perpetuity, as of the beginning of the third, or "terminal" stage.[17] Witness Gorman assumes a long-term growth rate of 4.90 percent, which is the approximate average of the five year (2015 - 2019) and ten year (2020 - 2024) nominal GDP growth rate

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16 *See* Document No. 11 of my exhibit.

17 *See* Exhibit MGP-9, Page 1 of 1.

estimates, as reported by *Blue Chip*.[18] Consequently, Witness Gorman's long-term GDP growth rate projection, which he applies to years eleven through 200 of his model (that is, from year 2024 through 2212), covers only year eleven (that is, 2024). That is, despite the fact that the *Blue Chip* projection period ends in 2024, witness Gorman uses it as the measure of expected perpetual GDP growth beginning in 2024.

Since the *Blue Chip* forecast is applicable only to a single year of witness Gorman's terminal stage, I developed an alternative analysis (*see* Document No. 12 of my exhibit). In that analysis, I continue to include the *Blue Chip* forecast, but only in the period to which it applies. Since the *Blue Chip* forecast terminates in 2024, I added a fourth stage, which incorporates an additional estimate of long-term growth beyond the period represented by the *Blue Chip* forecast. As discussed in more detail below, the fourth-stage growth rate represents the combination of the long-term historical average real GDP growth rate, and the market's expectation of long-term inflation beginning ten years from now. Limiting the *Blue Chip* forecast to the period to which it applies, and incorporating the alternative estimate of long-term growth increases the mean and

[18] *See* direct testimony of Michael P. Gorman, at 34 and Exhibit MPG-9. Witness Gorman calculates his nominal GDP growth rates based on separate Blue Chip consensus forecasts for real GDP growth and growth in the GDP Chained Price Index for the periods 2015-2019 and 2020-2024. At page 33 of his direct testimony, witness Gorman points to the EIA Annual Energy Outlook, which projects real GDP growth in the range of 2.0 to 2.90 percent for the years 2011 through 2040, and Congressional Budget Office projections of real GDP growth from 2.20 percent to 2.60 percent over the coming five to ten years.

median DCF results by 47 to 48 basis points.

Q. Are there other benchmarks that put witness Gorman's 4.90 percent long-term growth rate in context?

A. Yes, there are. While witness Gorman suggests that the reasonableness of his ROE estimates may be viewed in the context of his long-term growth projections, an alternative approach is to assess his long-term growth projections in the context of recently authorized ROEs. Given that witness Gorman's Risk Premium approach is premised on the use of authorized returns as a measure of "expectational" data,[19] it would follow that the long-term growth rate assumed in his Multi-Stage DCF model should produce results that are reasonably consistent with current expectations (that is, with recently authorized equity returns).

Knowing that his average Multi-Stage DCF estimate is 8.89 percent, and that recently authorized equity returns are quite a bit higher (*see* Document 40 of my exhibit, and Exhibit MPG-12), it is reasonable to question the terminal growth rate used in witness Gorman's Multi-Stage DCF analysis. As shown in Document No. 13 of my exhibit, keeping all of witness Gorman's data and assumptions

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19 *Ibid.*, at 37.

constant but for the terminal growth rate, and solving for the growth rate that produces an average ROE of 10.01 percent[20] produces an implied growth rate of 6.31 percent.[21] That, of course, is substantially above witness Gorman's 4.90 percent estimate, although it is quite consistent with the long-term geometric average nominal GDP growth rate of 6.23 percent.[22]

Q. Is there another approach to calculating the long-term growth rate that produces more reasonable results than witness Gorman's 4.90 percent estimate?

A. Yes, there is. As witness Gorman points out in footnote 16 of his direct testimony (page 33), nominal GDP growth is the product of real GDP growth and inflation. It is possible to use observable market data regarding nominal and inflation-protected Treasury yields (referred to as "Treasury Inflation Protected Securities" or "TIPS") to calculate the market's forward view of inflation (that is, inflation expected over the long term beginning ten years from now). In particular, the difference between nominal Treasury yields and TIPS yields is commonly considered to be a measure of expected inflation. Because the expected rate of inflation is easily calculated, all that is needed is an estimate of long-

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20 10.01 percent represents the average authorized ROE in 2012 for electric utilities. In performing this analysis I am not suggesting that 10.01 percent is an appropriate return for Tampa Electric.

21 *See* Document No. 13 of my exhibit.

22 Source: Bureau of Economic Analysis

term real GDP growth.

Q. Is there a method that can be used to estimate projected long-term real GDP growth beginning ten years from now?

A. Yes, there is. In his response to the CAPM analysis contained in my direct testimony, witness Gorman refers to the long-term average rate of capital appreciation (from 1926 through 2012) as a measure of the market's expectation of the forward-looking (that is, the expected) rate of growth. As witness Gorman explains, he uses "this gauge of actual capital appreciation in the market in the past as an estimate of future expected growth of the market index going forward…"[23] That same approach can be applied to real GDP growth; historical real GDP growth can be used as a measure of expected real GDP growth in the terminal period. According to data provided by the Bureau of Economic Analysis, over the period 1929 to 2012 the average annual real GDP growth rate was 3.22 percent (on a geometric average basis). Combining real GDP growth with the expected inflation rate of 2.29 percent produces an expected long-term growth rate of 5.59 percent.[24]

Q. With those points in mind, did you make any additional

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[23] direct testimony of Michael P. Gorman, at 59.

[24] [(1.0322) x (1.0229)] - 1 = .0559.

adjustments to witness Gorman's analysis?

A. Yes, Document No. 14 of my exhibit provides the incremental results of those adjustments. To ensure that I correctly applied the analysis, I first recreated witness Gorman's Multi-Stage model and replicated his results. I then updated the market data used in that model to July 12, 2013, and adjusted witness Gorman's Internal Rate of Return calculation to reflect the mid-year convention (as explained above). Next, I revised the long-term growth rate used in the final stage of witness Gorman's model to the more reasonable estimate of perpetual long-term nominal GDP growth described above. The cumulative effect of those adjustments is to increase the average ROE estimate to 9.60 percent. Although that result remains well below a reasonable estimate of the Company's Cost of Equity, it is meaningfully above witness Gorman's 9.25 percent ROE recommendation.

Q. Aside from those adjustments to witness Gorman's model, did you provide your own Multi-Stage DCF analysis?

A. Yes, I did.

Q. Please generally describe the structure of your Multi-

Stage model.

A. The Multi-Stage model that I have included in response to witness Gorman's analysis focuses on cash flow growth rates over three distinct stages. As with the Constant Growth form of the DCF model, the Multi-Stage form defines the Cost of Equity as the discount rate that sets the current price equal to the discounted value of future cash flows. Unlike the Constant Growth form, however, the Multi-Stage model included in my rebuttal testimony is solved in an iterative fashion.

As noted above, the model sets the subject company's stock price equal to the present value of future cash flows received over three "stages". In the first two stages, "cash flows" are defined as projected dividends. In the third stage, "cash flows" equal both dividends and the expected price at which the stock is sold at the end of the period (i.e., the "terminal price"). I calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the Cost of Equity (i.e., the discount rate) and the long-term expected growth rate. In essence, the terminal price is defined by the present value of the remaining "cash flows" in perpetuity.[25] In

[25] The terminal rate equals the 5.59 percent expected nominal GDP growth discussed earlier in my response to witness Gorman.

each of the three stages, the dividend is the product of the projected Earnings Per Share, and the expected dividend payout ratio.

Q. What are the primary analytical benefits of your three-stage model?

A. The primary benefits relate to the flexibility provided by the model's structure. Since it provides the ability to specify near, intermediate, and long-term growth rates, for example, the model avoids the sometimes-limiting assumption that the subject company will grow at the same, constant rate in perpetuity. In addition, by calculating the dividend as the product of earnings and the payout ratio, the model enables analysts to include assumptions regarding the timing and extent of changes in the payout ratio to reflect, for example, increases or decreases in expected capital spending, or a transition from current payout levels to long-term expected levels. In that regard, because the model relies on multiple sources of earnings growth projections, it is not limited to a single source, such as Value Line, for all inputs, and mitigates the potential bias associated with relying on a single source of growth estimates.[26]

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[26] *See*, for example, Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992).

The model also enables the analyst to assess the reasonableness of the inputs and results by reference to certain market-based metrics. For example, the stock price estimate can be divided by the expected Earnings Per Share in the final year to calculate an average P/E ratio. Similarly, the terminal P/E ratio can be divided by the terminal growth rate to develop a Price to Earnings Growth ("PEG") ratio. To the extent that either the projected P/E or PEG ratios are inconsistent with historical or expected levels, it may indicate incorrect or inconsistent assumptions within the balance of the model.

Q. What were your specific assumptions with respect to the payout ratio?

A. For the first two periods I relied on the first year and long-term projected payout ratios reported by Value Line,[27] for each of the proxy companies. I then assumed that by the end of the second period (i.e., the end of year 10), the payout ratio will converge to the industry expected ratio of 66.67 percent.[28]

Q. Please summarize the results of your Multi-Stage DCF analysis.

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[27] As reported in the Value Line Investment Survey as "All Div'ds to Net Prof."

[28] Source: Bloomberg Professional.

A. My Multi-Stage DCF analysis produces a range of results from 9.47 percent to 10.67 percent; the upper end of that range is consistent with my recommended ROE range, and with recently authorized returns in credit-supportive regulatory jurisdictions such as Florida.

Application of Capital Asset Pricing Model

Q. Please summarize witness Gorman's CAPM analysis.

A. witness Gorman develops a single CAPM estimate, which is based on the average of two separate Market Risk Premium estimates. Witness Gorman's first MRP estimate (7.50 percent) is based on the long-term historical (arithmetic) average real market return from 1926 through 2012 as reported by Morningstar, which he then adjusts for current inflation forecasts.[29] witness Gorman's second MRP estimate (5.70 percent) represents the historical difference between the average return on the S&P 500, and the average total return on long-term government bonds.[30] witness Gorman then relies on *Blue Chip*'s projected 30-year Treasury yield of 3.70 percent as the risk-free rate, and Beta Coefficients provided by Value Line to calculate his 8.60 percent average CAPM result.[31]

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29 *See* direct testimony of Michael P. Gorman, at 43.
30 *Ibid.*, at 43.
31 direct testimony of Michael P. Gorman, at 58.

Q. Does witness Gorman note any objections to your CAPM analysis?

A. Yes, witness Gorman asserts that my DCF-derived MRP estimate is based on a growth rate c that is "far too high" to be "sustainable",[32] and argues that my Sharpe Ratio approach relies on volatility measures that are short-term and inappropriate for utility investors.[33] Because witness Gorman's concern with the "sustainability" of growth rates arises in other aspects of his testimony, I address his specific concern regarding the expected market growth rate below.

Q. What is the basis of witness Gorman's assertion that your DCF-derived market return estimate is not "sustainable"?

A. witness Gorman notes that the earnings growth rate component of my DCF-derived market return is higher than estimates of long-term nominal GDP growth and on that basis, concludes that those projections are "far too high to be a rational outlook for sustainable long-term market growth."[34] witness Gorman supports his position by noting that the rate of "capital appreciation for the S&P 500 over the period 1926 through 2012" was 7.50 percent.[35] Adding the market average dividend yield of 2.00 percent

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32 *Ibid.*, at 59.
33 *Ibid.*, at 60.
34 *Ibid.*, at 58.
35 *Ibid.*, at 59.

to that 7.50 percent rate of growth, witness Gorman concludes that a reasonable expectation of the total market return would be 9.50 percent, which would translate to a "going-forward expected market risk premium of 6.4 percent."[36]

Q. Turning first to the expected total return on the market, do you agree with witness Gorman's 9.50 percent estimate?

A. No, I do not. Since witness Gorman supports his position in terms of the historical rate of capital appreciation, it also is appropriate to consider the expected market return in the context of historical market returns. In that regard, from 1926 through 2012, the arithmetic average market return (including the 7.50 percent capital appreciation rate noted by witness Gorman) was 11.80 percent,[37] 230 basis points above witness Gorman's 9.50 percent estimate.

Because witness Gorman concludes that the market return estimates used in my analyses are "too high" relative to historical levels, it also is instructive to understand how often various ranges of total returns actually have occurred over the 1926 to 2012 period. To perform that analysis, I gathered the annual return on Large Company

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36 *Ibid.*, at 59.

37 The return on Large Company Stocks, as reported by Morningstar, is the source on which witness Gorman relies to arrive at his 7.50 percent historical average capital appreciation rate.

Stocks reported by Morningstar, produced a histogram of those observations, and calculated the probability that a given market return estimate would be observed. The results of that analysis, which are presented in Document No. 15 of my exhibit, demonstrate that returns of 13.00 percent and higher actually occurred quite often.

In fact, the 12.93 percent and 13.00 percent estimates, which witness Gorman considers excessive by historical standards, represent the 49th percentile of the actual returns observed from 1926 to 2012. In other words, of the 87 annual observations, 44 were 13.00 percent or higher. By that measure, my estimate is not too high; it is entirely consistent with the historical experience that witness Gorman considers relevant.

Q. Turning now to witness Gorman's position that your MRP estimate is too high, did you also consider where your estimates fall within the range of historical observations?

A. Yes, I did. Similar to my review of observed market returns, I gathered the annual Market Risk Premia reported by Morningstar and produced a histogram of the observations. The results of that analysis, which are

presented in Document No. 16 of my exhibit, demonstrate that MRPs of at least 9.85 percent (generally the range of the MRP estimates in my direct testimony; *see* direct testimony and Exhibit of Robert B. Hevert, Document No. 5, Page 1 of 1 of my exhibit) have occurred nearly half of the time.

I then considered a different perspective, calculating the cumulative probability of the same ranges of MRP estimates. Those results, which are provided in Document No. 17 of my exhibit, demonstrate that (based on historical observations) there is approximately a 45.00 percent likelihood that an MRP of at least 10.00 percent will occur.

Those data present another important point: the annual average MRP of 6.70 percent is quite heavily influenced by a small number of large, negative observations. In 2008, for example, the MRP was negative 41.40 percent and as a result, the average long-term MRP fell. In other words, in the year during which market risk and uncertainty were at historically high levels, the historical average MRP suggested that investors required a significantly lower Return on Equity investments than they did on Treasury securities. In fact, from 2007-2012

the historical average MRP decreased from 7.10 percent to 6.70 percent, while market volatility increased from 17.54 percent to a high of 32.69 percent in 2008 and eventually fell to 17.80 percent in 2012.[38] That is, the effect of the 2007 to 2009 financial dislocation, in which realized returns fell and volatility increased, was to decrease the long-term average MRP.

The assumption that investors became less risk averse (as manifested in a lower MRP) during periods of increasing market uncertainty (as measured by the volatility of returns in 2008) is counter-intuitive, and in my view, leads to unreliable analytical results.

Q. Does witness Gorman's observation that the historical rate of capital appreciation has been 7.50 percent relate to other aspects of his ROE analyses and recommendations?

A. Yes, it does. As noted earlier, witness Gorman's DCF analyses reflect his view as to what may or may not represent a "sustainable" rate of growth. Witness Gorman compares analyst growth rates used in the Constant Growth DCF analysis with the *Blue Chip* projection of nominal GDP growth (4.90 percent).[39] As noted earlier, despite the fact that it is disconnected in time from its application

[38] Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 142 - 143 and Bloomberg Professional.

[39] *See* direct testimony of Michael P. Gorman, at 26-27.

in his analysis,[40] witness Gorman also relies on the *Blue Chip* nominal GDP growth projection as the terminal growth rate in his Multi-Stage DCF analysis.

While witness Gorman suggests that 4.90 percent represents the upper limit on long-term growth, he also estimates the long-term forward-looking expected return on the market by assuming the 7.50 percent historical rate of capital appreciation. In other words, witness Gorman appears to be of the view that 4.90 percent is a reasonable measure of long-term growth for the DCF model, and that 7.50 percent is an appropriate measure of long-term growth to estimate the expected market return. It is important to recognize that the growth component of the constant growth DCF model represents the expected rate of capital appreciation; the same is true of the terminal growth rate used in his multi-stage DCF analysis.[41] Consequently, the 7.50 percent rate of capital appreciation that witness Gorman assumes for the purpose of his expected market return also represents a measure of expected long-term growth.

In essence, witness Gorman's various analyses assume long-term growth rates of 4.90 percent to 7.50 percent. The growth estimates used in my Constant Growth DCF model

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40 As noted earlier, the Blue Chip projection period ends in the year in which witness Gorman uses it as the estimate of expected *perpetual* GDP growth.

41 As noted in my direct testimony, the Constant Growth DCF model assumes that earnings, dividends, and book value all grow at the same, constant rate in perpetuity (see direct testimony of Robert B. Hevert, at 22). Those assumptions imply that the Market-to-Book and price/earnings ratios stay constant. The same basic assumptions hold for witness Gorman's "sustainable growth" model.

(5.78 percent on average) and the long-term growth estimate assumed in my Multi-Stage DCF analysis (5.59 percent) fall within that range. Consequently, witness Gorman's assertions that my growth rate estimates are somehow inflated are inconsistent with his own data and assumptions.

Q. What would be the effect of reflecting the long-term capital appreciation rate (7.50 percent) in the Multi-Stage DCF analysis?

A. If we were to keep witness Gorman's 4.90 percent growth rate as the third-stage estimate, but include the 7.50 percent long-term capital appreciation rate noted in witness Gorman's testimony, the mean and median Multi-Stage DCF result would increase to 10.74 percent (*see* Document No. 12 of my exhibit). That estimate, of course, is well within my recommended range.

Q. What are your conclusions regarding witness Gorman's CAPM analysis?

A. As a practical matter, witness Gorman's CAPM result is nearly 200 basis points below the Commission's decision in Docket No. 120015-EI. Consequently (and for the

reasons discussed above), I agree with witness Gorman's decision to place "minimal weight" on his 8.60 percent CAPM estimate.[42]

Application of the Risk Premium Model

Q. Please briefly describe witness Gorman's Risk Premium analyses.

A. witness Gorman defines the "Risk Premium" as the difference between average annual authorized equity returns for electric utilities, and a measure of long-term interest rates each year from 1986 through 2012. Witness Gorman's first approach calculates the annual risk premium by reference to the 30-year Treasury yield, and the second considers the average A-rated utility bond yield.[43] In each case, witness Gorman discards the three lowest and three highest implied equity risk premia, and establishes the range of Risk Premium estimates based on the next highest (or lowest) estimate. In other words, the lower bound of his Risk Premium range is defined by the fourth-lowest risk premium, regardless of the year in which it occurred. In a similar manner, the upper bound of witness Gorman's Risk Premium range is defined by the fourth-highest estimate, regardless of the year in which that observation occurred. Witness Gorman then applies

42 *See* direct testimony of Michael P. Gorman, at 46.
43 *See* Exhibits MPG-11 and MPG-12.

weights of 25.00 percent and 75.00 percent, respectively, to his lower and upper bound estimates.[44]

As to the period over which he gathers and analyzes his data, witness Gorman suggests that his 27-year horizon is a "generally accepted period to develop a risk premium study using 'expectational' data."[45] witness Gorman further notes that "it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns", and concludes that his "risk premium study is based on expectational data, not actual returns, and, thus, need not encompass very long time periods."[46] Based on those assumptions, witness Gorman calculates a range of estimates from 7.72 percent to 9.88 percent, and produces a return estimate of 9.28 percent, which he rounds to 9.30 percent.[47]

Q. Does witness Gorman rely on his Risk Premium model in making his ROE recommendation?

A. Yes, he does. As noted above, witness Gorman develops his ROE estimate (i.e., 9.25 percent) at least in part based on his Risk Premium results.[48]

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44 *See* direct testimony of Michael P. Gorman, at 36 and 39.
45 *Ibid.*, at 37.
46 *Ibid.*, at 38.
47 *Ibid.*, at 39-40.
48 *Ibid.*, at 46.

Q. What are your specific concerns with witness Gorman's Risk Premium analyses?

A. I have several concerns with witness Gorman's analysis: (1) his method of relying on the fourth lowest and highest risk premium is arbitrary and establishes a range of ROE estimates that are predicated on economic and financial conditions that are far removed from the current market; (2) witness Gorman's method and recommendation ignore an important relationship revealed by his own data, i.e., that the Risk Premium has a strong negative correlation to the level of interest rates (whether measured by Treasury or utility bond yields); and (3) the low end of witness Gorman's Risk Premium estimates, which is well below his CAPM estimate (which he gave minimal weight in developing his ROE range and recommendation), is far lower than any ROE authorized since at least 1986 and as such, has no relevance in estimating the Company's Cost of Equity.

Q. Turning first to the method by which witness Gorman selected the bounds of his Risk Premium estimates, have you reviewed the range of data included in his analysis?

A. Yes, I have. Considering first the Treasury yield-based

analysis, I plotted the yields and Risk Premia over the 1986 to 2012 period included in witness Gorman's analysis. That graph is presented in Document No. 18 of my exhibit.

There are several important points that may be taken from that data. First, the low end of witness Gorman's Risk Premium range, 4.41 percent, was observed in 1987 and 1991 (that is, during the second Reagan administration and the G.H.W. Bush administration). It is apparent that a discrete observation from an economic environment 26 years ago has little to do with current market conditions. In fact, a very visible measure of such differences is the fact that in 1987, Treasury yields exceeded the Risk Premium. As Document No. 18 of my exhibit demonstrates, however, since the turn of the Millennium, the opposite has been true; the Risk Premium has consistently exceeded Treasury yields. By that measure alone, it is clear that the low end of witness Gorman's range has little, if any, relevance to the current market environment.

As to the high end of his range, witness Gorman's convention of discarding the three highest Risk Premium estimates has the effect of ignoring observations from

2009, 2011 and 2012. Since 2008, the Federal Reserve has proceeded on a steady path of initiatives (including the extension of Quantitative Easing announced on June 19, 2013) designed to lower long-term Treasury yields.[49] By not including the most recent data in his analysis, witness Gorman's method fails to recognize the decrease in Treasury yields and the concurrent, and considerable, increase in the Risk Premium.

Q. Please elaborate on your last point, that the Risk Premium has increased as Treasury yields have decreased.

A. As Document No. 18 of my exhibit demonstrates, over witness Gorman's study period the Risk Premium has moved inversely to changes in Treasury yields. While witness Gorman suggests that such a relationship may be "simplistic", it clearly is supported by his own data;[50] the correlation between the two is negative 86.78 percent (*see* Document No. 18 of my exhibit). To put that degree of correlation in perspective, if the two were to move in exactly opposite directions, the correlation would be negative 100.00 percent, if they did not move together at all, the correlation would be zero. Because correlation coefficients by definition are between zero and one (either positive or negative), a correlation of negative

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49 *See* Federal Reserve Press Release dated June 19, 2013.

50 direct testimony of Michael P. Gorman, at 62. Please also see page 37 of my direct testimony and in particular footnote 29 in which I cite academic articles that conclude such a relationship does exist.

86.78 percent indicates a strong tendency for the Equity Risk Premium to increase as interest rates decrease. While witness Gorman suggests that there is no academic support for the position that the Risk Premium is inversely related to changes in interest rates, Dr. Roger Morin notes that:

> [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates - rising when rates fell and declining when interest rates rose.[51]

In fact, several of the articles cited by Dr. Morin also were cited in my direct testimony.[52]

Turning back to witness Gorman's data, a simple linear regression analysis reveals that for every 100 basis point decrease in yields, the Risk Premium increases by approximately 44 basis points (*see* Document No. 18 of my exhibit).[53] That result is consistent with those found by Maddox, Pippert and Sullivan, who determined that the Risk Premium would increase by 37 basis points for every 100 basis point change in the 30-year Treasury yield.[54]

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51 Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. (2006), at 128 [clarification added].

52 *See* direct testimony of Robert B. Hevert, at 37.

53 Adjusting for serial correlation does not materially affect the results; *see* Document No. 18 of my exhibit.

54 *See* Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Vol. 24, No. 3, Autumn 1995, at 93.

Citing Harris and Marston, the authors note a similar estimate of 36 basis points.[55] While witness Gorman suggests that other variables may be at play, he has provided no insight as to whether those variables (e.g., credit spreads) would materially affect the interest rate/Risk Premium relationship. Adding credit spreads as an explanatory variable, for example, does not alter the fundamental negative relationship between interest rates and the Equity Risk Premium (*see* Document No. 18 of my exhibit). If anything, allowing for the "unusually wide Treasury to utility bond yield spreads"[56] noted by witness Gorman would increase the estimated ROE (the regression coefficient relating to the credit spread is positive).

Q. Have you made any adjustments to witness Gorman's analysis to reflect the concerns discussed above?

A. Yes, I have. While I continue to believe that the regression analysis included in my direct testimony is the appropriate method, I have adjusted witness Gorman's analysis to reflect the Risk Premium associated with the prevailing level of interest rates. Based on witness Gorman's Exhibit MPG-11, the average 30-year Treasury yield in 2011 and 2012 was 3.42 percent; the average Risk Premium during those years was 6.70 percent. Applying

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55 *Ibid.*

56 *See* direct testimony of Michael P. Gorman, at 40.

the projected 3.70 percent (30-year) Treasury yield to that risk premium produces an ROE estimate of 10.40 percent. Assuming the respective 2011 and 2012 Risk Premium estimates (combined with the projected 3.70 percent Treasury yield) produces a range of 10.01 percent to 10.79 percent. While the low end of the range is somewhat below my recommended range, those estimates are far more consistent with observed authorized returns than witness Gorman's 7.72 percent to 9.88 percent range.[57]

Q. Have you completed a similar analysis using witness Gorman's Utility Bond Yield data?

A. Yes, those results are consistent with my analysis of witness Gorman's Treasury yield-based Risk Premium. Here again, it is clear that the Risk Premium has increased as the Utility Bond Yield has decreased. In fact, because the two have been moving steadily in opposite directions, the Risk Premium now is higher than the Bond Yield. Witness Gorman, however, developed his Risk Premium (and, therefore, his ROE) estimates based on data points that occurred more than 17 years prior to that point of inversion. Even the high end of witness Gorman's Risk Premium estimate (which is based on calendar year 2010) is derived from data reflecting a period in which the

[57] *Ibid.*, at 39. Please note that I address witness Gorman's assumption that a return estimate as low as 7.72 percent should be given any weight in more detail below.

Bond Yield exceeded the Risk Premium and as such, produces an ROE estimate that is incompatible with the current market environment.

Q. Do you have any other observations regarding witness Gorman's Risk Premium analysis?

A. Yes, I do. Aside from the shortcomings discussed above, witness Gorman's Risk Premium recommendation gives considerable weight to ROE estimates that are well below the lowest return that has ever been authorized. Of the 1,410 electric utility rate authorizations since 1980 for which authorized ROEs were disclosed, the lowest was 8.75 percent.[58] witness Gorman, however, gives specific weight to ROE estimates that (on average) are over 100 basis points below that 8.75 percent level. It also is important to recognize that the 7.72 percent and 8.11 percent ROE estimates, each of which witness Gorman gave 25.00 percent weight, are well below his average CAPM result (8.60 percent) to which he gave no specific weight in arriving at his ROE recommendation.

Capital Market Conditions and Investor Risk Perceptions

Q. Please briefly summarize witness Gorman's position regarding current capital market conditions and their

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58 Source: Regulatory Research Associates.

effect on the Company's Cost of Equity.

A. Witness Gorman presents a review of general electric utility industry credit outlooks and stock price performance, and concludes that the market has embraced "the electric utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities."[59] witness Gorman further states that my discussion "ignores market sentiments toward utility companies, and instead lumps utility investments in with general corporate investments."[60] The risk metrics discussed in my direct testimony, however, relate specifically to the effect of capital market conditions on utility companies generally and electric utilities in particular.[61] Consequently, witness Gorman is incorrect when he concludes that I somehow have "lumped" utilities together with "general corporate investments."

Q. Do you agree with witness Gorman's conclusions regarding utility stock valuations and their implications for the Company's Cost of Equity?

A. No, I do not. While witness Gorman suggests that "utility stock investments are regarded by market participants as a moderate to low-risk investment,"[62] he

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59 *See* direct testimony of Michael P. Gorman, at 7-8.
60 *Ibid.*, at 65.
61 *See* direct testimony of Robert B. Hevert, Document Nos. 11, 12.
62 direct testimony of Michael P. Gorman, at 11.

fails to recognize that from July 12, 2012 through July 12, 2013, electric utilities were one of the worst performing equity market sectors. In fact, while the S&P 500 gained 25.88 percent, witness Gorman's proxy group[63] gained only 4.04 percent (*see* Document No. 19 exhibit). On relative basis, therefore, electric utilities were among the weakest industry sectors over the last year.

IV. RESPONSE TO HUA WITNESS BAUDINO AS IT RELATES TO THE COMPANY'S COST OF EQUITY

Q. Please summarize witness Baudino's ROE analyses and ROE recommendation in this proceeding.

A. Witness Baudino recommends an ROE of 9.30 percent, which is based on the results of his Constant Growth DCF analyses.[64] Although witness Baudino performs several CAPM analyses, he does not "directly incorporate [those] results" in his ROE recommendation.[65]

Witness Baudino notes that interest rates have declined from January 2002 through May 2013, and suggests that the required Return on Equity also is lower.[66] As to its capital structure, witness Baudino accepts the Company's proposed 54.20 percent equity ratio, but suggests that doing so makes his ROE recommendation conservative.[67]

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63 witness Gorman relied on the same proxy group included in my direct testimony.

64 *See* direct testimony of Richard A. Baudino, at 2. [Clarification added]

65 *Ibid.*

66 *Ibid.*, at 4, 12. *See* also Exhibit RAB-2.

67 *See* direct testimony of Richard A. Baudino, at 33-34.

Lastly, because he believes they are accounted for in the stock prices used in DCF analyses, witness Baudino suggests it is unnecessary to reflect flotation costs in his ROE estimate.[68]

Q. What are the principal areas in which you disagree with witness Baudino's ROE analyses?

A. The principal areas in which I disagree with witness Baudino include: (1) his sole reliance on the Constant Growth DCF model to determine the Company's Cost of Equity; (2) the growth rates applied in the Constant Growth DCF model; (3) the risk-free rate and Market Risk Premium used in the CAPM; (4) whether the Bond Yield Plus Risk Premium analysis provides reasonable estimates of the Company's Cost of Equity; (5) the recovery of flotation costs; and (6) our respective assessments of the Company's level of business and financial risk. In addition, while witness Baudino and I disagree regarding the selection and composition of our respective proxy groups, those differences do not appear to account for a meaningful difference in our analytical results or recommendations. Nonetheless, I briefly discuss our different proxy company selection criteria, below.

[68] *Ibid.*, at 47-48.

Proxy Group Composition

Q. Please summarize the criteria by which witness Baudino selected his proxy group.

A. witness Baudino began with the electric utilities included in the July 2013 issue of *AUS Utility Reports*, and arrived at his proxy group by excluding companies that:

1. Were not rated "Baa" or "BBB" by Moody's Investor Service ("Moody's") or Standard and Poor's ("S&P");
2. Have eliminated dividend payments or recently cut dividend payments;
3. Were recently, or are currently involved in merger activities or significant restructuring; or
4. Had recent experience with significant earnings fluctuations.[69]

He then excluded Ameren Corporation and Edison International because of business challenges in their unregulated generation business segments. Witness Baudino also excluded PG&E Corporation due to near-term earnings growth uncertainty related to the recent gas pipeline explosions. Based on those criteria, witness Baudino arrived at a group of 16 companies.[70] Document No. 20 of my exhibit provides a comparison of the companies included in our respective proxy groups.

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69 *See* direct testimony of Richard A. Baudino, at 17-18. Note, witness Baudino excludes companies that have credit ratings from both Moody's and S&P that are either above, or below Baa/BBB.

70 *Ibid.*, at 17-19.

Q. Are the scope and definition of the screens applied by witness Baudino generally consistent with those used in your direct testimony?

A. While certain of the screening criteria are common to our analyses, there are certain differences between our approaches.

Q. What are the primary differences between you and witness Baudino with respect to screening criteria?

A. The majority of the difference in our approaches relate to witness Baudino's use of proxy companies that: (1) receive less than 90.00 percent of their regulated net income from electric operations; (2) do not have meaningful amounts of regulated generating assets; or (3) derive less than 10.00 percent of their generation from coal-fired power plants. In addition, four companies included in my proxy group were excluded by witness Baudino because their bond credit ratings were above Baa/BBB (Moody's/S&P).

As shown in Document Nos. 1, 2, and 5 of my exhibit, despite those differences, the composition of our respective proxy groups has little effect on the

differences in our analytical results. Consequently, the analyses accompanying my rebuttal testimony include results for a Combined Proxy Group that contains all of the proxy companies relied on by either witness Baudino or me.

Application of the Constant Growth DCF Analysis

Q. Please briefly describe witness Baudino's Constant Growth DCF analysis and results.

A. Witness Baudino calculates an average dividend yield of 4.00 percent by dividing each proxy company's annualized dividend by its average monthly stock price for the six-month period from January 2013 to June 2013.[71] For the expected growth rate, witness Baudino relies on Earnings Per Share growth rate projections from Value Line, Zacks, and Thomson, as well as Dividend Per Share growth rate projections from Value Line.[72] witness Baudino then calculates DCF results based on the mean and median growth rate of the four sources noted above, producing eight ROE estimates that range from 7.38 percent to 10.07 percent.[73]

Witness Baudino refers to the DCF results produced using mean growth rates as "Method 1", and DCF results produced

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71 *See* direct testimony of Richard A. Baudino, at 20. witness Baudino calculates the average monthly stock price as the average of the highest and lowest stock price for the month; *see* Exhibit RAB-8.

72 *See* also Exhibit RAB-9, page 2.

73 *Ibid.*

using median growth rates as "Method 2". The mean and midpoint DCF results of Method 1 were 9.32 percent and 9.08 percent, respectively. The mean and midpoint DCF results of Method 2 were 9.08 percent and 8.73 percent, respectively.[74]

Lastly, witness Baudino considers a form of "Sustainable Growth", although he does not appear to include that estimate in his final DCF analyses.

Q. Please summarize the differences between you and witness Baudino in the selection of growth rates in your DCF models.

A. Witness Baudino and I disagree in three general areas: (1) the use of projected dividend growth rates in estimating the Cost of Equity; (2) the criteria on which a given growth rate estimate may be considered appropriate for the purposes of the Constant Growth DCF model; and (3) the form of "Sustainable Growth" described in witness Baudino's testimony.

Q. Please explain your concern with witness Baudino's use of projected dividend growth rates in the DCF model.

[74] *See* direct testimony of Richard A. Baudino, at 25; See also Exhibit RAB-9, Page 2 of 2.

A. As noted in my direct testimony, earnings are the fundamental driver of a company's ability to pay dividends.[75] Management decisions to conserve cash for capital investments, to manage the dividend payout for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can influence dividend growth rates in near-term periods. Over the long-run, however, dividends are dependent on and will increase as a function of earnings. Since the DCF model assumes cash flows based on a constant dividend payout ratio in perpetuity, earnings, rather than dividends, are the appropriate measure of growth.

I also note that Value Line is the only service noted in witness Baudino's testimony that provides dividend growth projections. To the extent that the earnings projections services such as Zacks and Thomson Financial used by both witness Baudino and me represent survey data, the results are less likely to be biased in one direction or another.

Q. Is the use of analysts' earnings growth projections in the DCF model supported by academic literature?

A. Yes, a number of published articles support the use of analysts' earnings growth projections in the DCF model. A

[75] See direct testimony of Robert B. Hevert, at 24.

1986 article entitled *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return* by Dr. Robert Harris, for example, demonstrated that financial analysts' earnings forecasts (referred to in the article as "FAF") in the Constant Growth DCF formula are an appropriate method of calculating the expected MRP.[76] In that regard, Dr. Harris noted that:

> ...a growing body of knowledge shows that analysts' *earnings* forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average of forecasts by individual analysts.[77]

Dr. Harris further noted that:

> Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements.[78]

Similarly, in *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts*, Harris and Marston presented "estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts."[79] In that regard, Harris and Marston reported that,

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76 *See* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, 1986 at 66.

77 *Ibid.*, at 59. Emphasis added. As noted in my direct testimony, Zacks and First Call, the sources of earnings growth projections that I use in addition to Value Line, are consensus forecasts.

78 *Ibid.*, at 60.

79 Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992.

> ...in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.[80]

Here again, the finding was clear: analysts' earnings forecasts are highly related to stock price valuations and, therefore, are appropriate inputs to stock valuation and ROE estimation models.[81] As discussed below, that conclusion also holds true for the universe of electric utilities covered by Value Line.

Q. Please describe the analyses you performed to assess the relationship between stock prices and projected earnings and dividend growth rates.

A. My analyses were based on the fundamental premise of the Constant Growth DCF model, i.e., that the current market price is a function of expected growth. As discussed in more detail below, my analyses examine the relationship between the current Price/Earnings ("P/E") ratios as the dependent variable with (projected) Earnings Per Share ("EPS") and Dividend Per Share ("DPS") growth rates (as provided by Value Line) as the explanatory variables.

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80 *Ibid.*, at 63.

81 In *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, published in Financial Management, Spring 1985, Brigham, Shome and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data; and (ii) investors do rely on analysts' forecasts."

The intent was to determine whether projected earnings or dividend growth rates are statistically related to the companies' P/E ratios.

Q. What did those analyses reveal?

A. As shown in Document No. 21 of my exhibit, the analyses indicate that projected dividend growth is not a statistically significant explanatory variable; projected earnings growth rate, on the other hand, is statistically significant.[82] That is, while EPS growth rates have a statistically significant ability to explain changes in valuation levels, DPS growth rates do not.

Q. Do you have any other concerns with the projected Dividend Per Share growth rates used by witness Baudino?

A. Yes. In particular, I note the Value Line dividend growth rate estimates on which witness Baudino relies include growth estimates significantly below the projected rate of inflation. By relying on those estimates, witness Baudino implicitly has assumed that investors would commit capital to a company expected to have negative real growth *in perpetuity*. Since witness Baudino excluded Otter Tail Corporation's 21.50 percent earnings

[82] For the reasons discussed later in my response to witness Baudino, Document No. 21 of my exhibit also includes Book Value Per Share growth rates.

growth rate from his DCF calculation for being "anomalous"[83], I believe it would have been appropriate for witness Baudino to exclude negative real growth rate projections, as well.

As Document No. 22 of my exhibit demonstrates, after eliminating negative real growth rates from witness Baudino's DCF analysis, the mean projected Dividend Per Share growth rate increases from 4.29 percent to 5.69 percent (an increase of 140 basis points).[84] Similarly, the median projected Dividend Per Share growth rate increases from 3.31 percent to 5.50 percent (219 basis points).

While I do not agree with the use of Dividend Per Share growth rates, I note that after eliminating negative real growth rates, the mean and median Dividend Per Share growth rate is generally consistent with the mean and median Earnings Per Share growth rates on which witness Baudino relies. As Document No. 22 of my exhibit also demonstrates, excluding negative real dividend growth rates would increase witness Baudino's "Method 1" mean and midpoint DCF results from 9.32 percent and 9.08 percent to 9.68 percent and 9.63 percent, respectively. The same adjustment would increase witness Baudino's

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83 direct testimony of Richard A. Baudino, at 18, 24. witness Baudino also excluded PNM Resources from his proxy group because he found the dividend and earnings growth rate projections (12.50 percent and 12.00 percent, respectively) "excessive" and "non-constant"; *see* direct testimony of Richard A. Baudino, at 38.

84 A 2.21 percent expected rate of inflation was calculated as the difference between the 30-day average of the 30-year nominal Treasury yield (3.46 percent) and the 30-year TIPS yield (1.25 percent) as of July 12, 2013.

"Method 2" mean and midpoint DCF results from 9.08 percent and 8.73 percent to 9.64 percent and 9.67 percent, respectively. While those adjusted results remain well below a reasonable estimate of the Company's Cost of Equity, they do demonstrate the sensitivity of witness Baudino's results to reasonable changes in the growth rate assumption.

Q. Does witness Baudino discuss other growth rate estimates in his testimony?

A. Yes, witness Baudino states that he "utilized the sustainable growth formula", which (as discussed in more detail below) he appears to have taken from Value Line's projected "Retained to Common Equity" rate.[85] As witness Baudino explains, the estimate is calculated as the product of the expected earned return on common equity ("R"), and the retention ratio (*i.e.*, the portion of earnings not paid out in dividends, or "B").[86]

Q. Do you agree with witness Baudino's sustainable growth rate estimate?

A. No, I do not. The Sustainable Growth model assumes that growth is a function of expected earnings, and the extent

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85 direct testimony of Richard A. Baudino, at 23-24. The sustainable growth rates reported in Exhibit RAB-9 are equal to Value Line's reported projections for Retained to Common Equity, as shown in Document No. 23 of my exhibit.

86 *Ibid.*

to which those earnings are retained (that is, not paid out in dividends. As discussed below, witness Baudino relies on the simplest form of the Sustainable Growth model, which sometimes is referred to as the "B x R" approach (where "B" is the earnings retention rate, and "R" is the expected Return on Common Equity). As Document No. 23 of my exhibit demonstrates, the B x R method is essentially equal to Value Line's "Retained to Common Equity" rate (differences are due to rounding).

If witness Baudino is going to consider a form of Sustainable Growth, he should use the "BR + SV" form of the model, which reflects growth from both internally generated funds (*i.e.*, the "BR" term) and from issuances of equity (*i.e.*, the "SV" term). As noted above, the first term is the product of the retention ratio (*i.e.*, "B", or the portion of net income not paid in dividends) and the expected return on equity (*i.e.*, "R"). The "SV" term can be represented as:

$$\left(\frac{m}{b} - 1\right) \times \textit{Growth Rate in Common Shares}$$

Where:

$$\frac{m}{b} = \textit{The Market to Book Ratio}$$

In this form, the "SV" term reflects an element of growth as the product of (1) the growth in shares outstanding and (2) that portion of the market-to-book ratio that exceeds unity.

In addition, it is important to realize that for the purpose of setting utility rates, the Sustainable Growth method of estimating long-term growth requires an estimate of the earned Return on Common Equity. Since the "R" in the "B x R" approach refers to the equity return, witness Baudino effectively has pre-supposed the Return on Common Equity projected by Value Line for his proxy group companies. Notwithstanding that witness Baudino has assumed the reasonableness of Value Line's projections for the purpose of his Sustainable Growth calculation, as demonstrated in Document No. 23 of my exhibit, his recommended Cost of Equity of 9.30 percent is 117 basis points below the mean Return on Common Equity estimate (for his proxy group) of 10.47 percent.

Q. Putting aside those concerns, did witness Baudino use the sustainable growth estimate in arriving at his DCF estimate?

A. No, he did not. Exhibit RAB-9, page 2 provides the DCF

calculations that support witness Baudino's ROE recommendation; that page does not reference the Sustainable Growth estimate.[87] In addition, I have replicated witness Baudino's Exhibit RAB-9, page 2 (*see* Document No. 22 of my exhibit), and confirmed that witness Baudino's DCF estimates do not include his Sustainable Growth estimate.

Multi-Stage DCF Analysis

Q. Given witness Baudino's concern with Value Line's Earnings Per Share growth rate estimate for Otter Tail Corporation and his use of dividend growth rate projections in the Constant Growth DCF model, is there a second form of the DCF model that may be considered?

A. Yes, as discussed in my response to witness Gorman (above), I have considered the results of a Multi-Stage DCF model.

Capital Asset Pricing Model

Q. Please summarize witness Baudino's CAPM analyses.

A. As noted earlier, witness Baudino performs two sets of CAPM analyses. His first set calculates two Market Risk Premium measures, which rely on the forecasted market

87 *Ibid.*, at 25. *See* also Exhibit RAB-9.

total return as determined using Value Line projections, and five and 20-year Treasury security yields (*i.e.*, 0.87 percent and 2.77 percent, respectively). Witness Baudino calculates a total growth rate for the market of 11.43 percent, using the average of the book value and earnings growth forecasts (9.22 percent and 13.64 percent, respectively) for all companies covered by Value Line. Witness Baudino combines that average growth rate with Value Line's average expected dividend yield of 0.75 percent for the same group of companies, and calculates an expected market return of 12.18 percent.[88]

Witness Baudino's two Market Risk Premium measures represent the difference between (1) his calculated expected market total return, and (2) the current yield on five and 20-year Treasury securities. Witness Baudino arrives at his CAPM results using the average Value Line Beta coefficient of 0.71 for his proxy companies.[89]

Witness Baudino's second set of CAPM analyses calculate the geometric and arithmetic mean long-term annual returns on stocks, and long-term annual income returns on long-term government bonds, resulting in two historical measures of the Market Risk Premium.[90] witness Baudino uses those two Market Risk Premium measures in

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88 *Ibid.*, at 28-31. *See* also Exhibit RAB-10 and Exhibit RAB-11.

89 *Ibid.*, at 28-30. *See* also Exhibit RAB-10.

90 The difference between the return on stocks and the income return on government bonds represents the historical Market Risk Premium.

combination with the current 20-year Treasury bond yield and the average Value Line Beta coefficient to calculate two additional CAPM results.[91]

Although witness Baudino advises the Commission to consider only his DCF results in establishing the Company's ROE,[92] he does report CAPM results ranging from 6.10 percent to 9.44 percent, reasoning that those results indicate that his 9.30 percent ROE recommendation is "generous".[93]

Q. Do you agree with witness Baudino's application of the CAPM and his interpretation of its results?

A. No, there are two areas in which I disagree with witness Baudino: (1) the term of the Treasury security used as the risk-free rate component of the model; and (2) the calculation of the Market Risk Premium. In addition, for the reasons discussed throughout my rebuttal testimony, I disagree that witness Baudino's 9.30 percent ROE recommendation is "generous".

Q. Turning first to the risk-free rate component, why do you disagree with witness Baudino's use of five and 20-year Treasury securities as the measure of the risk-free rate?

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91 *See* direct testimony of Richard A. Baudino, at 29-31. *See* also Exhibit RAB-11.

92 *Ibid.*, at 31-32.

93 *Ibid.*, at 31-32.

A. As discussed below, the tenor of the risk-free rate used in the CAPM should match the life (or duration) of the underlying investment. As noted by Morningstar:

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[94]

Pratt and Grabowski recommend a similar approach to selecting the risk-free rate: "In theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are expected."[95] To that point, a 2004 paper titled *Applying*

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[94] Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 44.

[95] Shannon Pratt and Roger Gabrowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.

The Capital Asset Pricing Model by Robert Harris reviews current practices for application of the CAPM and, when summarizing best current practices, concludes "[t]he risk-free rate should match the tenor of the cash flows being valued."[96] As a practical matter, equity securities represent a perpetual claim on cash flows; 30-year Treasury bonds are the longest-maturity securities available to match that perpetual claim.

One measure of the term of expected cash flows is Equity Duration. In finance, "duration" (whether for bonds or equity) typically refers to the present value weighted time to receive the security's cash flows. In terms of its practical application, duration is a measure of the percentage change in the market price of a given stock in response to a change in the implied long-term return of that stock. A common investment strategy is to "immunize" the portfolio by matching the duration of investments with the term of the underlying asset in which the funds are invested, or the term of a liability being funded.

As demonstrated in Document No. 24 of my exhibit, the average Equity Duration of the companies in witness Baudino's proxy group is approximately 26.70 years.

[96] Paper cited with permission of author.

Given that relatively long Equity Duration, and knowing that utility assets are comparatively long-lived, I continue to believe that it is appropriate to use the long-term Treasury yield as the measure of the risk-free rate.

Q. Is witness Baudino's assumption that five and 20-year Treasury yields are equally valid measures of the risk-free rate supported by his data?

A. No, it is not. As discussed above, the mean Equity Duration of the companies in witness Baudino's proxy group is 26.70 years. In comparison, the current duration of five-year, 20-year and 30-year Treasuries are 4.88, 15.15, and 19.14 years respectively.[97] While the duration of even the longest-term Treasury security falls short of the average Equity Duration for witness Baudino's proxy group, the 30-year Treasury yield provides the longest available duration and, therefore, the best available security for that purpose. The principle of duration is relevant to the electric utility stocks that comprise witness Baudino's proxy group, given that institutional investors own (on average) 63.45 percent of those companies' shares.[98]

[97] *See* Document No. 25 of my exhibit.
[98] *See* Document No. 26 of my exhibit.

Q. Putting aside the issue of Equity Duration, does witness Baudino's DCF model recognize the perpetual nature of equity?

A. Yes, it does. As witness Baudino correctly observes, the Constant-Growth DCF model assumes growth in perpetuity: "the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond)." [99]

Q. What would be the effect of assuming the companies in witness Baudino's proxy group only provided cash flows to equity investors over five or 20 years?

A. As shown in Document No. 27 of my exhibit, assuming a 20-year holding period, the mean and median DCF would be 2.83 percent, and 2.89 percent, respectively. Interestingly, both of those ROE estimates are nearly equal to witness Baudino's assumed 2.77 percent risk-free rate (i.e., six month average of the 20-year Treasury yield).[100] Assuming a holding period of five years produces mean and median ROE estimates of negative 34.46 percent and negative 34.66 percent, respectively. The only way witness Baudino's DCF results could be realized

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[99] direct testimony of Richard A. Baudino, at 15.
[100] Exhibit RAB-10, page 2.

is if the shares were sold at the end of the five and 20-year holding periods, *and* the prices at which they are sold reflect cash flows in perpetuity. Those results support the point made earlier in my testimony: the risk-free rate should reflect the perpetual nature of equity. Since the longest-dated Treasury security is 30 years, that is the appropriate term for this purpose.

Q. What is your response to witness Baudino's suggestion that "the risk-free rate should have no interest rate risk?" [101]

A. The process of duration matching mitigates interest rate risk. In any event, if witness Baudino is concerned with interest rate risk *per se*, he should focus exclusively on short-term Treasury Bills as the risk-free rate. Doing so, of course, would further decrease his already-low CAPM estimates. Consequently, I disagree with witness Baudino's position that interest rate risk disqualifies the 30-year Treasury yield as the appropriate measure of the risk-free rate.

Q. What concerns do you have with witness Baudino's *ex-ante* Market Risk Premium ("MRP") calculations?

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[101] direct testimony of Richard A. Baudino, at 43.

A. In arriving at his *ex-ante* Market Risk Premium estimates, witness Baudino calculates the expected market return using an average of earnings growth projections (13.64 percent) and book value growth projections (9.22 percent).[102] As noted above, academic research indicates investors rely on estimates of earnings growth in arriving at their investment decisions. The analysis presented in Document No. 21 of my exhibit (discussed in more detail above) also demonstrates book value growth rates are not a statistically significant indicator of electric utility company valuations. In that regard, witness Baudino did not include book value growth projections in his proxy group DCF analysis; he has not explained why it is reasonable to include those growth rates in his MRP analysis but exclude them from his proxy company DCF analyses. Excluding book value growth estimates from witness Baudino's market return calculation would increase his MRP estimate by 2.21 percentage points (221 basis points).[103]

Q. Do you agree with witness Baudino's use of historical estimates of the MRP?

A. No, I do not. As witness Baudino notes, using historical data to estimate the current MRP is "rather suspect

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102 *Ibid.*, at 28-30 and RAB-10.
103 2.21 percent equals 13.64 percent less 11.43 percent.

because it naively assumes that investors currently expect historic risk premiums to continue unchanged into the future regardless of present or forecasted economic conditions."[104] witness Baudino also cites to Brigham, Shome, and Vinson, noting that the MRP varies over time, and that historical estimates are sensitive to the period over which they are measured.[105] Nonetheless, witness Baudino presents CAPM analyses using both geometric and arithmetic average historical MRP estimates (4.70 percent, and 6.70 percent, respectively);[106] those estimates are significantly below the forward-looking MRP calculations discussed above.

Witness Baudino similarly notes "[t]here is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."[107] Despite those reservations, witness Baudino presents CAPM analyses that rely on historical measures of the Market Risk Premium, and points to those results as support for the position that his 9.30 percent ROE recommendation is "generous".[108]

Q. Please briefly summarize witness Baudino's comments regarding your *ex-ante* CAPM analyses?

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104 direct testimony of Richard A. Baudino, at 29.
105 *Ibid.*
106 *See* Exhibit RAB-10. *See also*, direct testimony of Richard A. Baudino, at 31. The MRPs are calculated as the average (geometric and arithmetic) stock return less the income-only portion of bond returns over the period 1926 to 2012.
107 direct testimony of Richard A. Baudino, at 30.
108 *Ibid.*, at 32.

A. witness Baudino disagrees with my Sharpe Ratio-derived Market Risk Premium, noting "it is highly unlikely that investors would use such an unorthodox method to derive their expected market risk premium and CAPM return."[109] witness Baudino further suggests that the forecasted Treasury bond yields relied upon in my CAPM analyses are "speculative at best and *may or may not* come to pass."[110]

Q. Do you agree with witness Baudino's concerns in that regard?

A. No, I do not. As to the Sharpe Ratio method, as discussed in my direct testimony that approach is meant to capture the interaction among expected volatility, interest rates, and the Market Risk Premium.[111] However, in order to narrow the scope of issues in dispute, my updated analyses do not rely upon the Sharpe Ratio calculation of the MRP. Rather, I continue to rely on two *ex-ante* estimates of the MRP derived from Constant Growth DCF model estimates of the total market return.

Regarding the use of projected interest rates, it is important to remember that, as witness Baudino states, "[r]eturn on equity analysis is a forward-looking process."[112] In that regard, witness Gorman, witness

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109 *Ibid.*, at 43.
110 *Ibid.*, at 42-43 [emphasis added].
111 direct testimony and Exhibits of Robert B. Hevert, at 32-33.
112 direct testimony of Richard A. Baudino, at 22.

Woolridge, and I consider forward looking estimates of the risk-free rate.[113] Even if witness Baudino is concerned that the projections may not come to pass, the increases in forward long-term Treasury yields discussed earlier in my rebuttal testimony demonstrate that investors believe interest rates are likely to rise. Since our analyses are predicated on market expectations, the expected increase in Treasury yields (as reflected in increasing forward rates) is a measurable and relevant data point.

Bond Yield Plus Risk Premium Approach

Q. What concerns does witness Baudino express regarding your Bond Yield Plus Risk Premium analyses?

A. Witness Baudino suggests that the Bond Yield Plus Risk Premium method is "imprecise and can only provide very general guidance," and notes that "[r]isk premiums can change substantially over time." In summary, witness Baudino likens the approach to a "blunt instrument".[114] As to its application, witness Baudino disagrees with the use of projected Treasury yields in calculating the range of Risk Premium-based results.[115]

Q. What is your response to witness Baudino's observations?

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113 *See* direct testimony of Michael P. Gorman, at 41. *See* also direct testimony of J. Randall Woolridge, at 42.

114 direct testimony of Richard A. Baudino, at 44 [clarification added].

115 *Ibid.*

A. As to witness Baudino's point that the Risk Premium can change over time, I agree: as noted in my direct testimony (and as discussed in my response to witness Gorman), there is a statistically significant negative relationship between long-term Treasury yields and the Equity Risk Premium.[116] Given witness Baudino's observation that interest rates have declined since 2002,[117] the Bond Yield Plus Risk Premium analysis provides an empirically and theoretically sound method of quantifying the relationship between the Cost of Equity and interest rates. That is, it provides a method to quantify the change that witness Baudino has observed.

As to witness Baudino's notion that the approach is a "blunt instrument," I disagree. As shown in Document No. 6 of my exhibit, the R-squared of the Bond Yield Plus Risk Premium regression analysis is 0.70, indicating a rather high degree of explanatory value.[118] In comparison, Beta coefficients calculated based on the Value Line methodology have a mean R-squared of only 0.42 (*see* Document No. 28 of my exhibit).[119]

As Document No. 29 of my exhibit demonstrates, using the 95.00 percent confidence interval of the Bond Yield Plus Risk Premium regression's equation coefficient estimates,

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116 *See* direct testimony of Robert B. Hevert, at 38.

117 *See* direct testimony of Richard A. Baudino, at 4. *See* also, Exhibit RAB-2.

118 R-squared is a measure of what percentage of the variation on the dependent variable is explained by variation in the independent variable of a regression equation.

119 witness Baudino relies exclusively on Value Line as his source of Beta coefficients. Value Line derives the Beta coefficient from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years. As noted earlier, while witness Baudino does not include his CAPM estimates in calculating his ROE recommendation, he does point to those results in determining that his recommendation is "generous".

the ROE results range from 9.67 percent to 11.45 percent. That 178 basis point range is well less than the range of DCF model results reported by witness Baudino (7.38 percent to 10.07 percent, or 269 basis points). It also is considerably less than the range of CAPM results reported by witness Baudino (6.10 percent to 9.44 percent, or 334 basis points).[120] Consequently, the Bond Yield Plus Risk Premium approach provides empirically and theoretically sound results that can be used, at minimum, to assess the wide range of ROE results produced by witness Baudino's analyses in general, and his 9.30 percent recommendation in particular.

Flotation Costs

Q. Please now summarize witness Baudino's response to your proposed flotation cost adjustment.

A. Witness Baudino believes it is "likely that flotation costs are already accounted for in current stock prices" and that an adjustment to the DCF result would amount to "double counting."[121] In addition, witness Baudino notes that TECO Energy has stated that it does not plan to raise new equity to fund its capital investment program.[122]

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120 *See* Exhibit RAB-9, Exhibit RAB-10, and Exhibit RAB-11.
121 direct testimony of Richard A. Baudino, at 47.
122 *Ibid.*, at 48.

Q. Do you agree with witness Baudino's concerns?

A. No, I do not. Witness Baudino states that "[m]ultiplying the dividend yield by a 4 percent flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting Cost of Equity."[123]

The flotation cost estimate used in my direct testimony, however, is well below 4.00 percent, and the adjustment is calculated by dividing the dividend yield by a factor of (1 - flotation costs).[124] Moreover, witness Baudino's suggestion that current prices "likely" account for flotation costs is misplaced. First, because of direct issuance costs (such as those provided in Document No. 8 of my exhibit to my direct testimony), the net proceeds received by the Company were less than the market price of the offerings. Absent a direct recovery of those costs, the ROE should be adjusted to reflect that deficiency (which will persist in perpetuity).[125]

I also note that while witness Baudino suggests that current prices "likely" account for flotation costs, he has provided no analyses as to what costs are reflected in

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123 *Ibid.*, at 48.

124 See direct testimony and Exhibit of Robert B. Hevert, Exhibit No. __(RBH-1), Document No. 8 of my exhibit.

125 *Ibid.*, at 49-50; *see* also Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. (2006), at 330-332.

prices, or how prices have adjusted in response to those costs. Conversely, my direct testimony provided a summary of direct costs incurred by TECO Energy to acquire the equity capital needed to fund the Company's rate base.[126]

Relative Risk and Financial Integrity

Q. Do you agree with witness Baudino's position that his ROE estimate is "conservative" in that his proxy group has a lower average credit rating than Tampa Electric?[127]

A. No, I do not. Credit ratings are directed toward the interests of debt investors. The view that differences in credit ratings "notches" among investment grade utilities can be used as a proxy for differences in the Cost of Equity also fails to recognize the senior position that debt holders have relative to equity holders, and the investment horizon considered by equity holders. For example, a long-term issuer credit rating is an opinion regarding the subject company's overall financial capacity to pay its financial obligations as they come due and payable.[128] The claims of equity holders, however, are subordinate to the claims of debt holders.

Because equity holders bear the residual risk of

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126 *See* direct testimony and Exhibit of Robert B. Hevert, Document No. 8 of my exhibit, Page 1 of 2.

127 direct testimony of Richard A. Baudino, at 17.

128 *See* Standard & Poor's Ratings Direct, *Standard & Poor's Ratings Definitions*, June 22, 2012, at 6.

ownership, when bondholders are given more comfort in the probability that the subject company will be able to meet its near-term financial obligations (and thus have higher credit ratings), equity holders still bear the incremental risk of insufficient or increasingly volatile cash flows over the long-term. For that fundamental reason, it is not clear that there is a direct relationship between credit notches and the Cost of Equity.

Q. Did you perform any analyses to determine whether witness Baudino's data supports the assumption that there is a quantifiable difference in the Cost of Equity for companies with different bond credit ratings?

A. Yes, I did. I first produced Constant Growth DCF results for each of the comparison companies using the growth rates and dividend yields reported by witness Baudino. I then applied "credit scores" to witness Baudino's comparison companies by converting the S&P bond ratings reported in his direct testimony to a numerical value.[129] If there is a quantifiable relationship between the proxy companies' credit ratings and Cost of Equity, there should be a positive, statistically significant relationship between the credit score and the DCF

[129] For example, the S&P bond credit rating A was assigned a value of 1, A- was assigned a value of 2, and so forth.

results. That is, as credit quality deteriorates (resulting in a higher score), the Cost of Equity should increase. I therefore performed a regression analysis, in which the dependent variable was the DCF result, and the explanatory variable was the credit score. As shown in Document No. 30 of my exhibit, the regression analysis showed no statistically significant statistical relationship between the two. In fact, the R-squared of the regression was only 1.81 percent which indicates that credit ratings accounted for only 1.81 percent of the change in the DCF-estimated Cost of Equity.[130]

Q. Does the fact that Standard & Poor's ranks Tampa Electric as having an "Excellent" Business Risk Profile and "Significant" Financial Risk indicate they have less risk than other electric utilities?[131]

A. No, it does not. A recent review of regulated electric utilities credit ratings from S&P highlighted the prevalence of "Excellent" business risk profiles among electric utilities.[132] Of 173 electric utility parent and operating companies, S&P reported that 153 companies (*i.e.*, approximately 88.00 percent) had "Excellent" business risk profiles. Among those with "Excellent" business risk profiles, S&P's credit ratings ranged from

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130 As a point of reference (as noted earlier in my response to witness Baudino), my Risk Premium regression analyses has an R-Squared of approximately 70.00 percent.

131 See direct testimony of Richard A. Baudino, at 9.

132 *See* Standard & Poor's, *U.S. Regulated Electric Utilities, Strongest to Weakest*, October 12, 2012.

as high as AA- to as low as BB+ (*i.e.*, below investment grade). Similarly, approximately 51.00 percent of the companies had a "Significant" financial risk profile or better; those companies' S&P credit ratings ranged from AA- to BBB- (*see* Document No. 31 of my exhibit). As such, Tampa Electric's "Excellent" business risk and "Significant" financial risk profile from S&P does not distinguish the Company as being less risky than other electric utilities, nor does it insulate the Company from the detrimental effects of witness Baudino's ROE recommendation.

Q. Has witness Baudino expressed any concerns with your consideration of the business risks associated with Tampa Electric's high level of capital expenditures?

A. Yes. Witness Baudino suggests that the Company's credit rating already accounts for the risk of high capital expenditure levels, and that the magnitude of the Company's capital expenditure plans is in the bottom quintile or third of (depending on projection year) of the companies included in SNL's industry report.[133]

Q. What is your response to witness Baudino's position?

[133] *See* direct testimony of Richard A. Baudino, at 45-46.

A. Regarding Tampa Electric's credit rating, as noted above that credit ratings reflect the perspective of debt holders and do not reflect the incremental risk faced by equity holders. Moreover, the data provided by SNL reports each company's planned investments on an absolute basis; it does not provide context for the investments relative to the reporting companies' size. As such, I calculated the ratio of expected capital expenditures to net assets for each of the companies in witness Baudino's proxy group (*see* Document No. 32 of my exhibit).[134] For the projected period from 2014-2018, I performed that calculation using the Company's projected capital expenditures over that period relative to its projected total net assets as of December 31, 2014. For the proxy companies, I relied on projected capital expenditure projections from Value Line.[135] As discussed in my direct testimony, Tampa Electric expects to invest $350 million each year for the next five years to support system reliability and modest customer growth, and an additional $610 million relating to the Polk Power Station combined cycle conversion.[136] Tampa Electric's 54.38 percent ratio of projected capital expenditures to rate base was above the mean and median of witness Baudino's proxy group (50.61 percent and 48.74 percent, respectively).

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134 As witness Baudino points out on page 16 his direct testimony, the intent of his proxy group is to develop a "group of companies with a risk profile that is reasonably similar to Tampa Electric." As such for the purpose of this analysis, I relied on witness Baudino's proxy group and Value Line, a source on which witness Baudino relies.

135 I note that Mr. Baudino relies on Value Line projections of dividend growth in his DCF analysis.

136 direct testimony of Robert B. Hevert, at 40.

V. RESPONSE TO OPC WITNESS WOOLRIDGE AS IT RELATES TO THE COMPANY'S COST OF EQUITY

Q. Please provide a brief summary of witness Woolridge's testimony and ROE recommendation.

A. Witness Woolridge recommends an ROE of 9.00 percent (assuming common equity ratio of 50.00 percent), which represents the upper end of his DCF and CAPM results; he recommends an ROE of 8.75 percent if the Commission adopts the Company's proposed capital structure.[137] In developing his ROE recommendation, witness Woolridge relies primarily on the Constant Growth DCF model, which reflects a variety of growth measures, including growth in dividends, book value, and earnings. Although witness Woolridge gives "greater weight" to his Constant Growth DCF model, he suggests that his ROE recommendation is supported by currently low interest rates and low "expected returns on financial assets."[138]

Q. What are the principal areas of disagreement between you and witness Woolridge?

A. The principal areas of disagreement include: (1) the composition of our respective proxy groups; (2) the growth rates applied in the Constant Growth DCF model;

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137 direct testimony of J. Randall Woolridge, at 50.

138 *Ibid.*, at 50.

(3) the application of the CAPM; (4) the reasonableness of the Bond Yield Plus Risk Premium analysis; (5) the effect of current capital market conditions on the Company's ROE; and (6) the Company's proposed capital structure as it relates to the Cost of Equity.

Proxy Group Selection

Q. Please describe the screening criteria by which witness Woolridge developed his proxy group.

A. Witness Woolridge relies on six screening criteria to develop his group of 34 companies:

1. Each company selected must be listed as an Electric Utility by Value Line and as an Electric Utility or Combination Electric and Gas company by AUS Utilities Report;
2. Proxy companies must derive at least 50.00 percent of revenues from regulated electric operations;
3. Selected companies must have an investment grade bond rating as reported by AUS Utilities Report;
4. Companies must have a consistent dividend record with no cuts or omissions for the past three years;
5. Each company must not be involved in an acquisition, or be the target of an acquisition in the past six months; and

6. Proxy companies must have long-term EPS growth forecasts available from Yahoo!, Reuters, or Zacks.[139]

Q. Do you agree with the screening criteria that witness Woolridge applied?

A. Not entirely. Although we do have certain criteria in common (for example we both exclude companies that are party to a significant corporate transaction or that do not consistently pay dividends), I do not believe that witness Woolridge's screens render a group of companies that is sufficiently comparable to Tampa Electric.

Q. What is your concern with witness Woolridge's use of revenue, rather than income, as a screening criterion.

A. Measures of income are far more likely to be considered by the financial community in making credit assessments and investment decisions than are measures of revenue. From the perspective of credit markets, measures of financial strength and liquidity are focused on cash from operations, which is directly derivative of earnings, as opposed to revenue. As part of its rating methodology, Moody's assigns a 40.00 percent weight to measures of

139 *Ibid.*, at 11-12.

financial strength and liquidity, of which 22.50 percent specifically relates to the ability to cover debt obligations with cash from operations.[140]

Just as rating agencies focus on measures of cash from operations, equity analysts likewise prefer measures of income in assessing equity valuation levels. Common measures of valuation, for example, include the Price/Earnings ratio, the Price/Earnings to Growth ("PEG") ratio and the ratio of Enterprise Value/EBITDA (Earnings Before Interest, Taxes, Depreciation, and Amortization). The reason, of course, is that measures of revenue can obscure the assessment of the underlying value of the subject company. Energy marketing businesses, for example, typically are characterized by high volumes and comparatively low margins. Consequently, focusing on revenue may mislead the analyst into assuming that such segments are the primary driver of long-term growth, when, as a practical matter, the majority of earnings and cash flows are derived from other business segments. In this instance, in which we are considering whether the underlying utility is the predominant source of long-term growth, it could be misleading to focus on revenue rather than earnings.

140 *See, Rating Methodology, Regulated Electric and Gas Utilities,* Moody's Global Infrastructure Finance, August 2009, at 13.

Document No. 20 of my exhibit summarizes the reasons that I have excluded many of the companies included in witness Woolridge's 34-company proxy group.

Application of the Constant Growth DCF Analysis

Q. Please summarize the differences between you and witness Woolridge regarding the Constant Growth DCF model.

A. As a preliminary matter, I note that witness Woolridge's analysis produces an average DCF result of 8.70 percent[141] (which is five basis points below witness Woolridge's 8.75 percent ROE recommendation). I strongly disagree that a DCF result as low as 8.70 percent is relevant in determining the Company's Cost of Equity. As noted earlier, not only is witness Woolridge's DCF result 180 basis points below the Commission's recent decision in Docket No. 120015-EI, there has not been a single case in which an ROE as low as 8.70 percent was authorized for an electric utility since at least 1980.[142] As discussed below, witness Woolridge's low DCF results are largely explained by the growth rates that he has applied in his analysis.

Q. What growth rates does witness Woolridge include in his Constant Growth DCF analysis?

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141 Exhibit JRW-10, page 1 of 6. Reflects "Panel A" results.
142 Source: Regulatory Research Associates.

A. Witness Woolridge arrives at his assumed growth rate based on a review of a number of data points, including: historical and projected DPS, BVPS, and EPS growth rates as reported by Value Line; consensus EPS growth rate projections from First Call, Reuters, and Zacks; and an estimate of "sustainable growth." Witness Woolridge indicates that he has given more weight to projected EPS growth rates in arriving at his 4.50 percent growth rate estimate.[143]

As to the use of projected earnings growth rates, witness Woolridge asserts that there is an upward bias in those estimates and as such, "the DCF growth rate needs to be adjusted downward from the projected EPS growth rate."[144] Witness Woolridge also discusses the weaknesses he perceives in relying solely on forecasted EPS growth rates for the purpose of the DCF model.[145] Despite those concerns, witness Woolridge relies on projected EPS growth rates from First Call, Reuters, and Zacks, as well as an estimate of Sustainable Growth.

Q. Does witness Woolridge express any specific concerns with your use of analysts' earnings growth projections in your DCF models?

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143 *See* direct testimony of J. Randall Woolridge, at 38.
144 direct testimony of J. Randall Woolridge, at 36.
145 direct testimony of J. Randall Woolridge, at 56 - 57.

A. Yes, witness Woolridge argues that analysts' earnings growth estimates are "overly optimistic and upwardly-biased", and that relying on such estimates is a methodological error.[146] It is important to note, however, that while witness Woolridge's position is based on his observations with respect to the broad market, he has provided no evidence that any of the growth rates used in my DCF analysis are the result of a consistent and pervasive bias on the part of the analysts providing those projections.

Q. What is your response to witness Woolridge in that regard?

A. First, in light of restrictions imposed by the October 2003 Global Research Analyst Settlement, it is unclear how or why utility analysts' estimates would continue to be biased, as witness Woolridge suggests. That settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows", and required the settling financial institutions to fund independent third-party research.[147] To that point, a 2010 article in Financial Analyst Journal found that analyst forecast bias has declined significantly or disappeared entirely

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146 *See* direct testimony of J. Randall Woolridge, at 55.

147 The 2002 Global Financial Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts.

since the final judgment was issued in October 2003:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that of related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[148]

Based on a review of disclosures contained in recent analyst reports for certain of the proxy companies, it is apparent that the standard industry practice is to avoid conflicts of interest by ensuring that compensation is not, either directly or indirectly, linked to the opinions contained in those reports. In fact, some go so far as to demonstrate the specific factors that determine compensation, including the accuracy of earnings estimates, which creates a disincentive for either over-

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148 Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at 105. I recognize that witness Dr. Woolridge also refers to this article in his Appendix B.

or under-estimating earnings.[149]

Q. Please summarize witness Woolridge's analyses regarding the use of consensus earnings growth rate projections.

A. Witness Woolridge compares the actual three-to-five-year EPS growth rates and forecasted EPS growth rates for all the companies covered by I/B/E/S.[150] His results indicate that on average, for all industries covered by I/B/E/S, analysts' projected EPS growth rates have exceeded historical EPS growth. As witness Woolridge notes, however, there were "negative forecast errors" (*i.e.*, analysts' EPS forecasts understated actual growth in EPS) following the recessions of 1991 and 2001.[151] Witness Woolridge performs a similar analysis using I/B/E/S-covered electric and gas utilities. Witness Woolridge draws his conclusions regarding the accuracy of analysts' long-term earnings growth rates based on the forecast error experienced across all industries covered by I/B/E/S, as well as the I/B/E/S-covered utilities from 1994 through 2008, suggesting that the proxy companies likewise are susceptible to persistent and biased forecast errors.[152]

Q. Do you agree with witness Woolridge's assertion in that

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149 *See* for example, BMO Capital Markets, Viewpoint, September 18, 2012, at 8.

150 Institutional Brokerage Estimate Service (I/B/E/S).

151 *See* direct testimony of J. Randall Woolridge, Exhibit JRW-16, Appendix B, at 9.

152 *Ibid.*, at 13-14.

regard?

A. No, I do not. While witness Woolridge suggests that "long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased,"[153] and that growth rates for utilities display a similarly upward bias,[154] when viewed in the context of our respective proxy groups, analysts have been more likely to under-estimate, than over-estimate earnings.

Q. Please describe the analysis you performed to address witness Woolridge's assumption that the proxy companies' earnings growth estimates are biased.

A. The analysis examines the extent to which the consensus forecast earnings either under- or over-estimated annual earnings from 2002 through 2012 for each of the proxy companies used by either witness Woolridge or me. Based on data provided by Bloomberg, Document No. 33 of my exhibit demonstrates that the average annual difference between actual and projected earnings (that is, the "Earnings Surprise") for companies in either my proxy group or witness Woolridge's proxy group was 1.45 percent. That is, on average, actual earnings exceeded projected earnings for our combined proxy groups. Over

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153 Direct testimony of J. Randall Woolridge, at 35.

154 *See* direct testimony of J. Randall Woolridge, Exhibit JRW-16, Appendix B, at 13-14. *See* also Exhibit JRW-16, Appendix B1, Page 1 of 6.

that period, analysts were 1.67 times more likely to under-estimate, than to over-estimate annual earnings. On that basis, there is no basis to conclude that the earnings projections included in our analyses are likely to be systemically biased.

I understand that annual earnings estimates are not the long-term growth rate projections used in the Constant Growth DCF model. However, if witness Woolridge is correct and earnings projections are overly optimistic it would stand to reason that such a bias would exist in annual forecasts as well. As demonstrated above, that has not been the case. If anything, analysts covering the proxy group companies are somewhat conservative.

Q. What is your response to witness Woolridge's reference to the 2010 article by McKinsey & Company ("McKinsey") in support of his assertion that your DCF model relies on biased growth rates?[155]

A. The McKinsey article is general in nature, and does not indicate that there is a systemic bias on the part of utility analysts. In fact, while the article focuses on analysts' projections for the S&P 500, utilities are only one of ten sectors, and currently represent only 3.30

155 Exhibit JRW-16, Appendix B1, Page 3 of 6.

percent of the index.[156] Although he points to the article as support for this position that I should not have relied exclusively on utility analysts' presumably biased growth rate projections, witness Woolridge does not point out where the article states that any such bias extends to the utility sector, or whether it is concentrated in other, less stable industry sectors.

Moreover, witness Woolridge neglects to point out that the article observes that "…long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP, as prior McKinsey research has shown."[157] In a footnote to that sentence, McKinsey further states that "Real GDP has averaged 3 to 4 percent over past (*sic*) seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent."[158] The McKinsey article therefore supports the growth rates used in my Constant Growth and Multi-Stage DCF models: both are within the 5.00 percent to 7.00 percent range noted by McKinsey, and the terminal growth rate estimate used in my Multi-Stage DCF analysis represents the combination of historical real GDP growth and expected inflation.[159]

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156 McGraw Hill Financial, *S&P Dow Jones Indices*, August 5, 2013.

157 McKinsey & Company, McKinsey on Finance, Number 35, Spring 2010, *Equity Analysts: Still too bullish,* at 16-17.

158 Ibid., at 17.

159 Please also note that consistent with the McKinsey approach, the terminal growth rate used in my Multi-Stage DCF model is the product of real GDP growth (3.22 percent) and expected inflation (2.45 percent).

Q. Do you agree with witness Woolridge's position that dividend and book value growth rates are appropriate measures of expected growth for the Constant Growth DCF model?[160]

A. No, I do not. It is important to note that earnings growth enables both dividend and book value growth. That is, book value can increase over time only through the addition of retained earnings, or with the issuance of new equity. Both of those factors are derivative of earnings: retained earnings increases with the amount of earnings not distributed as dividends; and the price at which new equity is issued is a function of the EPS and the then-current P/E ratio. Similarly, as noted in my response to witness Baudino, earnings are the fundamental driver of a company's ability to pay dividends.[161]

In addition, Value Line is the only service relied on by witness Woolridge that provides DPS, BVPS, or Sustainable Growth projections. To the extent that the earnings projections services such as Zacks and First Call represent consensus estimates, the results are less likely to be biased in one direction or another as a result of an individual analyst.

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160 direct testimony of J. Randall Woolridge, at 31.

161 *See* also direct testimony and Exhibit of Robert B. Hevert, at 24.

Lastly, as shown in Document No. 34 of my exhibit, I recreated witness Woolridge's DCF analysis, relying on each of the average projected analyst growth estimates and the dividend yield in Exhibit JRW-10.[162] The results based on the DPS and BVPS growth rates are 8.64 percent, while the average result based on the EPS growth rates is 9.38 percent. While I do not believe that 9.38 percent is a reasonable estimate of Tampa Electric's ROE, it is 63 basis points higher than witness Woolridge's recommendation (assuming the Company's proposed equity ratio).

Q. Do you have any further observations regarding the growth rates used in witness Woolridge's DCF analysis?

A. Yes. First, it is interesting to note that in his "Building Blocks" approach to developing the equity risk premium, witness Woolridge has established an expected long-run nominal growth rate of 5.40 percent.[163] As witness Woolridge notes, it is not uncommon for analysts to use an estimate of long-term economic growth as a proxy for the long-term growth of the firm.[164] Given witness Woolridge's expected dividend yield of 4.20 percent, the DCF result would be approximately 9.60 percent.[165] While that result is still below a reasonable

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162 I also eliminated all growth rates less than or equal to zero as such estimates violate the basic assumption of the Constant Growth DCF model that dividends will grow in perpetuity.

163 *See* direct testimony of J. Randall Woolridge, Exhibit JRW-16, Appendix C, at 2-3. 5.40 percent equals the sum of the Expected Inflation amount of 2.75 percent and the Real Earnings Growth Rate of 2.65 percent. Using the convention assumed earlier in my rebuttal testimony, the nominal growth rate would be [(1.0275 x 1.0265)-1], or 5.47 percent. That estimate is only 12 basis points removed from my 5.59 percent long-term growth estimate.

164 *See* direct testimony of J. Randall Woolridge, at 61.

165 *See* Exhibit JRW-10, at 1 of 6. The estimated dividend yields include the one-half year convention for calculating the expected dividend yield.

estimate of the Company's Cost of Equity, it is approximately 60 to 90 basis points above witness Woolridge's DCF results, and 60 to 85 basis points higher than his recommended ROE. Looking to witness Woolridge's Exhibit JRW-14, page 2 of 3, the average growth rate of 6.36 percent would produce a DCF estimate of 10.56 percent, which is within my recommended range.

Q. Those differences aside, do you believe witness Woolridge's DCF analyses produce reasonable estimates of Tampa Electric's Cost of Equity?

A. No, I do not. The results of any given model must be interpreted in the context of current capital market conditions. Witness Woolridge's DCF analysis suggests an ROE estimate that is 225 to 255 basis points below the Company's currently authorized return, and 180 basis points below the Commission's recent decision regarding FP&L's Cost of Equity. As discussed in Section II, current capital market conditions cannot account for such a significant deviation.

Application of the CAPM

Q. Please briefly describe witness Woolridge's CAPM analysis and results.

A. Witness Woolridge's CAPM analysis produces an estimated Cost of Equity of 7.50 percent to 7.80 percent.[166] While witness Woolridge places greater weight on his DCF analysis, he nonetheless relies on his CAPM analysis in determining what he considers to be an appropriate range of the Company's Cost of Equity.[167] As with witness Woolridge's DCF results, I strongly disagree that a CAPM result of 7.80 percent (or lower) has any analytical value in determining the Company's ROE. As discussed below, witness Woolridge's rather low CAPM estimates are primarily the result of his estimated Market Risk Premium.

Q. Please describe how witness Woolridge calculated his Market Risk Premium estimate.

A. Witness Woolridge reviewed a series of studies that calculated the MRP using different methodologies; he also considered the results of his "Building Blocks" approach. Based on those reviews, witness Woolridge concluded that the MRP ranges from 4.50 percent to 5.50 percent and within that range, the midpoint of 5.00 percent is reasonable.[168] Witness Woolridge cites the results of three surveys, and suggests that his results are consistent with the views of Chief Financial Officers

166 Exhibit JRW-11, Page 1 of 6.
167 *See* direct testimony of J. Randall Woolridge, at 49.
168 *Ibid.*, at 48.

("CFO"), professional forecasters, and financial analysts.[169]

Q. What is your response to witness Woolridge on those points?

A. First, in referring to the *Duke CFO Survey* by Professors Graham and Harvey, witness Woolridge concludes that his estimated MRP is consistent with those used by CFOs.[170] In addition to certain measures of expected market returns, recent versions of the survey also asked respondents to provide their Weighted Average Cost of Capital ("WACC"), and Hurdle Rates.[171] Those two metrics are measures of the required, as opposed to the expected return. It also is important to note that the WACC includes both debt and equity; to the extent there is any debt in the capital structure, the WACC will be less than the Cost of Equity. In that regard, the mean WACC reported in the most recent survey for which those particular estimates were included, was 9.30 percent, and the mean Hurdle Rate was 13.50 percent.[172] Those rates, which are well in excess of the reported expected return, are more appropriate measures of required returns and are similar to the market returns of 12.72 percent and 13.44 percent in my updated calculation of the MRP.[173]

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169 *Ibid.*, at 45.

170 *Ibid.*, at 48.

171 The survey has not provided the results of these questions since June 2012.

172 *See, The Duke CFO Business Outlook Survey*, June 2012 Results, Table 10. The prevailing MRP based on the June 2012 survey was 4.50 percent with a Treasury bond yield of 1.80 percent and an expected return of 6.30 percent.

173 *See* Document No. 3 of my exhibit.

Second, by referring to the survey by the Federal Reserve Bank of Philadelphia, witness Woolridge suggests that his estimated MRP is consistent with those used by professional forecasters.[174] On reviewing that survey, I note that it does not specify whether the expected returns for the S&P 500 represent *total* returns or only capital appreciation. Specifically, the survey asks: "What do you expect to be the annual average [stock return] over the next ten years for the S&P 500?"[175] To the extent the Philadelphia Fed survey results include only capital gains but not dividends, the survey would understate the total return that investors expect.

Further, while the Survey of Professional Forecasters for the first quarter of 2013 considered the responses of 46 economists and financial forecasters, only 24 survey participants responded to the question regarding the expected return for the S&P 500 over the next ten years.[176] Similarly, only 26 responded to the questions regarding expected return on ten-year Treasury bonds.

Lastly, witness Woolridge cites a study by Pablo Fernandez, which found that the median MRP "employed by U.S. analysts and companies was 5.7 percent."[177] That study also discusses how the required equity risk premium

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174 *See* direct testimony of J. Randall Woolridge, at 48.

175 Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter of 2013, at 7.

176 *Ibid.*, at 17.

177 direct testimony of J. Randall Woolridge, at 48.

is commonly calculated using the Constant Growth DCF model:

> The [Implied Equity Premium] is the implicit [Required Equity Premium] used in the valuation of a stock (or market index) that matches the current market price. The most widely used model to calculate the [Implied Equity Premium] is the dividend discount model: the current price per share (P_0) is the present value of expected dividends discounted at the required rate of return (Ke). If d_1 is the dividend per share expected to be received in year 1, and g the expected long term growth rate in dividends per share,
>
> $P_0 = d_1 / (Ke - g)$, which implies:
>
> [Implied Equity Premium] = $d_1/P_0 + g - R_f$[178]

As explained in my direct testimony (and as discussed in my response to witness Baudino), I calculated the *ex-ante* MRP in a similar manner, using the market capitalization weighted average Constant Growth DCF result for the individual companies in the S&P 500 Index.

Q. Did witness Woolridge's express any concerns regarding your CAPM analysis?

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178 Pablo Fernandez, Javier Aguirreamalloa and Pablo Linares, *Market Risk Premium and Risk Free Rate used for 51 countries in 2013: a survey with 6,237 answers, IESE Business School, June 26, 2013, at 14.*

A. Witness Woolridge's primary disagreement with my CAPM analysis involves the Market Risk Premium component of the model. As to my use of expected market returns, witness Woolridge states that the result is "inflated due to errors and bias in [my] study."[179] Witness Woolridge also points to the long-term EPS growth rates for the S&P 500 of 10.88 percent and 10.93 percent based on the data from Bloomberg and Capital IQ, respectively,[180] and notes that they "are not consistent with historic as well as projected economic and earnings growth."[181]

Q. Turning to witness Woolridge's position that the EPS growth rates used to develop your estimated market return are too high, did you consider where your estimates fall within the range of historical observations?

A. Yes, I gathered the annual capital appreciation return on Large Company Stocks reported by Morningstar for the years 1926 through 2012, produced a histogram of those observations, and calculated the probability that a given capital appreciation return estimate would be observed. The results of that analysis, which are presented in Document No. 35 of my exhibit, demonstrate that capital appreciation rates of 10.00 percent to 11.00 percent and higher actually occurred quite often. In fact, the 10.88

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179 direct testimony of J. Randall Woolridge, at 62 [clarification added].

180 *Ibid.*, at 59.

181 *Ibid.*, at 60.

percent and 10.93 percent estimates, which witness Woolridge asserts are "overstated" by historical standards represent the 50th percentile of the actual capital appreciation rates observed from 1926 to 2012 (*see* Document No. 36 of my exhibit).

Bond Yield Plus Risk Premium Analysis

Q. Please summarize witness Woolridge's response to your Bond Yield Plus Risk Premium analysis.

A. Witness Woolridge believes that the Risk Premium derived from the analysis is "inflated" and "is a study of *Commission* behavior, not a study of *investor* behavior."[182] Based on the fact that Market-to-Book ratios for electric utilities have generally exceeded 100.00 percent, witness Woolridge suggests "that authorized rates of return have been greater than the return that investors require."[183] Witness Woolridge concludes that as a result, the Bond Yield Plus Risk Premium analysis overstates the actual ROE because, in his view, it "tends to perpetuate any past errors, and over time could become entirely disconnected from financial market realities."[184] Lastly, witness Woolridge believes that the approach is circular in that it relies on the outcome of past rate cases to determine the current Cost of Equity.[185]

182 *Ibid.*, at 66.
183 *Ibid.*, at 67.
184 *Ibid.*
185 *Ibid.*

Q. What is your response to witness Woolridge on those points?

A. As to his concern that Market/Book ("M/B") ratios above unity suggest authorized returns in excess of required returns, I note that the M/B ratio for the companies in the SNL Electric index, witness Woolridge's proxy group, and my proxy group have been significantly greater than 1.00 since at least 2000 (*see* Document No. 37 of my exhibit). It appears, then, that witness Woolridge believes that utility commissions have been consistently wrong for the last 13 years.

It also is important to note that the M/B ratio equals the market value (or stock price) per share, divided by the total common equity (or the book equity) per share. Book value per share is an accounting construct, which reflects historical costs. In contrast, market value per share (*i.e.*, the stock price) is forward-looking, and is a function of many variables, including (but not limited to) expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality", the regulatory climate, the equity ratio, expected capital expenditures, and the expected return on book equity.[186] Because the numerator (market value per share) and the denominator

[186] *See* for example, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 366. Please note that Dr. Morin cites several academic articles that address the various factors that affect the Market-to-Book ratio for utilities. In addition, the notion that book values should be set at a value approaching unity by regulatory commissions has been refuted for many years. As noted by Stewart Meyers in 1972: "In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that the market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book." Stewart C. Meyers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 3, No. 1 (Spring 1972), at 76.

(book value per share) are a function of different variables, M/B ratios over 100.00 percent do not necessarily imply that regulatory commissions have been consistently incorrect with respect to the returns that they have authorized.

Further, as noted in my direct testimony, the *Hope* and *Bluefield* guidelines establish that the fair rate of return on equity should be comparable to returns investors expect to earn on other investments of similar risk.[187] Assuming that regulatory commissions appropriately weigh the results of various models, analyses and expert testimony presented before them in order to determine a fair ROE that meets the *Hope* and *Bluefield* standards, authorized ROEs may be used as a proxy for investor return requirements.

Witness Woolridge's criticism of the Bond Yield Plus Risk Premium analysis would, therefore, only be valid if regulatory commissions consistently and significantly over or understated the Cost of Equity. Given that witness Woolridge does not provide any additional support for this claim beyond his general observation that M/B ratios for electric utilities have been greater than 100.00 percent, I disagree with his conclusion.

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187 *See* direct testimony of Robert B. Hevert, at 7-9.

Capital Market Conditions

Q. What are witness Woolridge's general observations regarding the current economic environment and its effect on the cost of capital?

A. Witness Woolridge states that "capital costs for utilities, as indicated by long-term bond yields, are still at historically low levels, even given the increase in these rates over the past two months."[188] In support of his position, witness Woolridge points to the significant intervention by the Federal Reserve, and decreases in bond yields since the peak of the economic crisis.[189] Witness Woolridge further suggests that because A-rated utility bonds have decreased by approximately 150 basis points since the Company's existing ROE was authorized, capital costs have decreased by the same amount.[190]

Q. What is your response to witness Woolridge's observations?

A. Witness Woolridge focuses his analysis on the low level of Treasury yields and bond yields through June 2013. As illustrated in Document No. 38 of my exhibit, however, the ten-year Treasury bond yield increased 95 basis

188 *See* direct testimony of J. Randall Woolridge, at 50.
189 *Ibid.*, at 8-9.
190 *Ibid.*, at 10.

points and the yield on Moody's A-rated utility bonds increased 84 basis points from May 1, 2013 through July 12, 2013. That is, the recent increase in interest rates has sustained itself beyond June 2013. In any case (and as discussed earlier in my rebuttal testimony), both current and forward interest rates are well above the levels that prevailed in December 2012 (that is, at the time of the reported decision date in Docket No. 120015-EI; *see* Document No. 40 of my exhibit).

Moreover, as discussed in my direct testimony (and in my response to Messrs. Gorman and Baudino), there is an inverse relationship between interest rates and the Equity Risk Premium. While interest rates have fallen since April 2009, the Equity Risk Premium has increased, suggesting that the Cost of Equity has not decreased in tandem with interest rates.[191] As such, witness Woolridge's review of the relatively low levels of the ten-year Treasury yields and long-term A-rated bond yields does not support his 8.75 percent to 9.00 percent ROE recommendation.

Capital Structure and the Cost of Equity

Q. Please summarize witness Woolridge's position on the Company's Cost of Equity as it relates to the Company's

191 *See* Documents No. 6 and 18 o my exhibit.

capital structure.

A. As noted earlier, witness Woolridge's ROE recommendation is dependent on the capital structure approved by the Commission in this proceeding. Specifically, witness Woolridge recommends an ROE of 8.75 percent if the Commission adopts the Company's proposed capital structure. If, however, the Commission adopts the capital structure proposed by OPC witness O'Donnell, witness Woolridge recommends an ROE of 9.00 percent.[192]

Q. In your direct testimony, you calculated the capital structures for the proxy group companies to assess the reasonableness of Tampa Electric's proposed capital structure. Have you performed a similar analysis of witness Woolridge's proxy group?

A. Yes. As discussed in my direct testimony, I analyzed the actual capital structures in place at the operating companies held within my proxy group. Doing so removes the effect of capital used to support unregulated operations, and reflects the nature of assets financed by vertically integrated utilities such as Tampa Electric. The operating utility company capital structures reflect a range of equity ratios range from a low of 47.99

192 *See* direct testimony of J. Randall Woolridge, at 17, 18.

percent to a high of 57.81 percent. As shown in Document No. 39 of my exhibit, I updated that analysis to include more recent data; that analysis provides a range of equity ratios range from 47.75 percent to 58.38 percent. While I disagree with many of the parent companies included in witness Woolridge's peer group, I have calculated the range and average equity for the utility operating companies held within that group as well. Witness Woolridge's proxy group companies' equity ratios range from a low of 45.01 percent to a high of 59.79 percent. On that basis, the Company's proposed capital structure which includes a 54.20 percent common equity ratio remains highly consistent with those of the utility operating companies held within my and witness Woolridge's proxy groups.

Q. Do the capital structures in place at the operating companies differ from those of the consolidated parent companies?

A. Yes, they do. As shown in Exhibit JRW-4, the average capital structure for witness Woolridge's proxy group companies at the consolidated level includes 45.90 percent common equity. As shown in Document No. 39 of my exhibit, for witness Woolridge's proxy group, the average

capital structure at the combined operating company level includes 51.78 percent common equity. This demonstrates that consolidated company capital structures can understate the average electric utility common equity ratio by more than 5.00 percentage points. That is, for the companies in witness Woolridge's proxy group, it is typical for the utility operating companies to have higher equity ratios than the consolidated parent companies. Therefore, witness Woolridge's comparison of the proxy companies' consolidated capital structures is inappropriate.

Q. What is your conclusion with respect to the Company's proposed capital structure and its effect on the Company's Cost of Equity?

A. I conclude that the Company's proposed 54.20 percent equity ratio is consistent with industry practice. I therefore disagree that the Company's ROE should be adjusted downward by 25 basis points, as witness Woolridge suggests.

VI. RESPONSE TO FRF WITNESS CHRISS AS IT RELATES TO THE COMPANY'S COST OF EQUITY

Q. Please briefly summarize witness Chriss' testimony as it

relates to the Company's Return on Equity.

A. As a preliminary matter, I note that witness Chriss does not perform an independent analysis of the Company's Cost of Equity. Rather, he reviews data for 65 reported electric utility rate cases (as reported by SNL Financial), which ranged from 9.00 percent to 10.50 percent, with an average of 9.97 percent and median of 10.00 percent. Removing the effect of distribution-only electric utilities, witness Chriss calculates an average authorized ROE of 10.05 percent.[193] Regarding the Commission's decisions in the Gulf Power Company case (Docket No. 110138-EI), and FP&L case (Docket No. 120015-EI), witness Chriss observes that the authorized ROEs of 10.25 percent and 10.50 percent, respectively, are below my specific ROE recommendation.[194]

Q. Are there other distinctions that are important to consider when reviewing Exhibit SWC-3?

A. Yes, there are. The Company's credit rating and outlook depend substantially on the extent to which rating agencies view the regulatory environment credit supportive, or not.[195] Moody's, for example, finds the regulatory environment to be so important that 50.00

193 *See* direct testimony of Steve W. Chriss, at 10 and Exhibit SWC-3.
194 *Ibid.*, at 9.
195 *See* direct testimony of Robert B. Hevert, at 61.

percent of the factors that weigh in the Company's ratings determination are determined by the nature of regulation.[196] Similarly, Standard & Poor's has noted that:

> The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most.[197]

Given the Company's need to access external capital, and in light of the weight that both Moody's and S&P place on the nature of the regulatory environment, I believe that it also is important to consider the extent to which the jurisdictions included in Exhibit SWC-3 are considered by rating agencies to be credit supportive.

Q. As a point of reference, is Florida generally considered a credit-supportive regulatory jurisdiction?

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196 Moody's *Global Infrastructure Finance, Regulated Electric and Gas Utilities*, August 2009, at 4.

197 Standard & Poor's, *Utilities: Assessing U.S. Utility Regulatory Environments*, updated November 15, 2011.

A. Yes, it is. S&P ranks regulatory jurisdictions according to the degree of credit-supportiveness. Florida is ranked "Credit Supportive," which is the second highest tier to which any jurisdiction in Exhibit SWC-3 is assigned.[198]

Q. How did you take those rankings into consideration in reviewing Exhibit SWC-3?

A. I first replicated Exhibit SWC-3, and ensured that I was able to calculate the same mean and median results. I then applied S&P's rankings (as represented by a numerical score) to the jurisdictions reported in Exhibit SWC-3 (*see* Document No. 40 of my exhibit).

Q. What did that analysis reveal?

A. The principal observation is that the median ROE for companies operating in jurisdictions that are considered at least "Credit Supportive" was 10.25 percent; the median for jurisdictions considered "More Credit Supportive" was 10.30 percent.

Q. Lastly, do you have any comments regarding witness Chriss' concern that the Company's proposed ROE is "excessive" in light of the economic circumstances faced

198 Standard & Poor's, *Utilities: Standard & Poor's Revises Its U.S. Utility Regulatory Assessments*, December 28, 2012, at 3.

by its customers?

A. Yes. I appreciate that the decision to seek rate relief is difficult. In my experience, those decisions always consider the effect on customers. Just as low rates are important, so is the financial strength of the incumbent utility. The ability to access the capital markets when and as needed provides the ability to invest in the assets needed to maintain system reliability and to enable growth. In that regard, I also appreciate that the Commission must balance those considerations in arriving at its ROE determination.

I also note that while witness Chriss speaks of customers generally, his testimony is on behalf of the Florida Retail Federation, and Walmart is a retail customer of Tampa Electric.[199] Although I cannot find financial information regarding all companies represented by the FRF and served by Tampa Electric, I note that based on its most recent report, Value Line assigns Walmart (NYSE: WMT) a Safety Ranking of 1, and a Financial Strength ranking of A++. By comparison, Value Line assigns TECO Energy a Safety Ranking of 2, and a Financial Strength Ranking of B++. By those measures, therefore, TECO Energy is more risky than Walmart. At the same time, Value Line

[199] *See* direct testimony and Exhibits of Steve W. Chriss, at 1. I recognize and appreciate that Walmart is a significant customer of Tampa Electric and that it provides both employment and services to the citizens of Florida.

projects Walmart to earn a Return on Common Equity[200] of 20.50 percent in 2014, and 21.00 percent in the 2016 to 2018 period, even considering current and expected economic conditions. Witness Chriss, however, recommends that the Commission authorize Tampa Electric, which Value Line considers to be more risky than Walmart, the opportunity to earn less than one-half of the equity return that Walmart is expected to earn.[201]

VII. RESPONSE TO OPC WITNESS O'DONNELL AS IT RELATES TO THE COMPANY'S CAPITAL STRUCTURE

Q. Please provide a brief summary of witness O'Donnell's recommendation as it relates to the Company's capital structure.

A. Witness O'Donnell recommends a capital structure consisting of 49.21 percent long-term debt, 0.79 percent short-term debt, and 50.00 percent common equity. witness O'Donnell arrives at his recommendation as a "middle ground between the Company's requested capital structure and the TECO Energy capital structure."[202] witness O'Donnell also observes the Company's proposed common equity ratio is higher than (1) the average common equity ratio authorized in other jurisdictions; and (2) TECO Energy.[203] In support of his position, witness

200 Please note that Value Line refers to Return on Common Equity as the "Return on Shareholder's Equity."

201 For the 2012 fiscal year, the Company's electric operations represented approximately 90.79 percent of TECO Energy's consolidated net income. *See* TECO Energy Inc., SEC Form 10-K for the Fiscal Year ended December 31, 2012, at 44.

202 direct testimony of Kevin W. O'Donnell, at 26.

203 *Ibid.*, at 26.

O'Donnell presents the December 31, 2012 common equity balances for each of Tampa Electric, Peoples Gas, the company's other non-regulated operations, and TECO Energy, reasoning that since the consolidated equity held at the parent level is less than the sum of the subsidiary equity balances, the Tampa Electric capital structure necessarily reflects the effects of double leverage.[204]

Q. Do you agree with witness O'Donnell's position that the capital structure should be adjusted to reflect the presumed effect of double leverage?

A. No, I do not. As discussed in the rebuttal testimony of Sandra W. Callahan, witness O'Donnell's recommendation is inconsistent with the widely accepted practice of utilizing the "stand-alone approach," which treats the utility subsidiary as its own company. Under the stand-alone approach, the cost of capital is determined using the subsidiary's own capital structure and cost of debt and equity; the Cost of Equity is estimated by reference to a proxy group of firms of comparable risk. Importantly, the stand-alone approach recognizes that the return should be based on the relative risk of the investment rather than the source of financing.

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204 *Ibid.*, at 16-17.

Q. Please explain your concern with witness O'Donnell's recommendation relative to the financial community's view of Florida regulation.

A. As mentioned elsewhere in my rebuttal testimony, there is no disagreement that Florida is considered a credit-supportive jurisdiction. As noted earlier, Moody's considers the regulatory structure to be so important that 50.00 percent of the factors that weigh in a ratings determination are related to the nature of regulation. Among the factors considered by Moody's in assessing the regulatory framework are the predictability and consistency of regulatory actions:

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors.

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> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[205]

As also discussed in witness Callahan's rebuttal testimony, if the Commission were to adopt witness O'Donnell's recommendation, it would represent a departure from recent precedent. In light of Moody's focus on "predictable and supportive treatment," I strongly disagree with witness O'Donnell that his recommendation somehow would not have any impact on how credit rating agencies view Tampa Electric. Such a dramatic change by the Commission from previous decisions would create an immediate and lasting concern for investors of the reasonableness of the regulation in Florida.

VIII. UPDATED RESULTS

Q. Have you updated the analyses presented in your direct testimony?

A. Yes. I have updated analyses presented in my direct testimony with data as of July 12, 2013. As noted in my

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205 Moody's Investors Service, *Regulatory Frameworks - Ratings and Credit Quality for Investor-Owned Utilities*, June 18, 2010, at 2.

response to witness Baudino, I performed the analyses for both the proxy group contained in my direct testimony ("Hevert Proxy Group") and a Combined Proxy Group comprised of all companies included in either the Hevert Proxy Group or witness Baudino's proxy group.

Q. Please summarize your updated DCF model results.

A. I have continued to use projected earnings growth rates from Zacks, First Call, and Value Line in developing my Constant Growth DCF model. The results are shown in Document No. 1 of my exhibit. As discussed in my response to witness Gorman, I also have performed a Multi-Stage DCF analysis; those results are presented in Document No. 2 of my exhibit.

Q. Please summarize your updated CAPM analysis.

A. Using the same data sources and assumptions, I updated my CAPM analysis with data as of July 12, 2013. For the reasons discussed in my response to witness Baudino, my updated CAPM analyses exclude the Sharpe Ratio based approach of estimating the Market Risk Premium. For the risk-free rate, I continue to refer alternatively to: (1) the 30-day average of the 30-year Treasury yield; (2)

a consensus near-term forecast of the average 30-Year Treasury yield; and (3) a consensus long-term forecast of the average 30-Year Treasury yield. For the Beta coefficient, I continue to rely on published results from Bloomberg and Value Line. For the MRP, I continue to refer to the form of *ex-ante* market risk premia that I described in my direct testimony.[206]

Q. What are your updated CAPM results?

A. As shown in Document No. 5 of my exhibit, based upon updated market information, my CAPM analyses produce a range of ROE estimates from 10.07 percent to 12.71 percent for the Hevert Proxy Group.

Q. Please summarize your updated Bond Yield Plus Risk Premium analysis.

A. My updated Bond Yield Plus Risk Premium analysis includes authorized ROEs as reported by Regulatory Research Associates through July 12, 2013. For the purpose of calculating the expected risk premium and ROE, I used the current and projected 30-year Treasury yield. As shown in Document No. 6 of my exhibit, my updated results range from 10.27 percent to 10.90 percent.

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206 As discussed in my rebuttal testimony, I did not include an estimate of the Sharpe Ratio-derived Market Risk Premium in my updated results. I relied on data from Bloomberg and Value Line for my updated estimates of the *ex-ante* Market Risk Premium (in my direct testimony I relied on data from Bloomberg and Capital IQ).

Q. Have you considered whether your recommended return meets the standard of a fair rate of return?

A. Yes. As noted in my direct testimony, my recommendation is based upon my understanding of the *Hope* and *Bluefield* standards.[207] Based on those standards, the consequence of the Commission's Order in this case should enable the Company to earn a fair and reasonable return and maintain its financial flexibility over the period during which rates are expected to remain in effect. My assessment also reflects the Company's need to attract capital at terms similar to those offered to companies of comparable risk. A recommendation that diminishes the Company's ability to compete for capital in the open market does not meet the "comparable company" standard.

IX. CONCLUSIONS AND RECOMMENDATION

Q. Please summarize the analyses and conclusions contained in your rebuttal testimony.

A. My updated analytical results are provided in Document Nos. 1 through 6 of my exhibit. My recommended ROE takes into account the results of these various models and analyses, as well as current and expected capital market conditions. In particular, my analyses and

[207] *See* direct testimony of Robert B. Hevert at 7-11.

recommendation reflect the recent and substantial increases in current Treasury yields, forward Treasury yields, and current dividend yields. Based on the data and analyses discussed throughout my rebuttal testimony, I conclude that the reasonable range of ROE estimates continues to be from 10.50 percent to 11.50 percent and within that range, 11.25 percent is a reasonable and appropriate estimate of the Company's Cost of Equity.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT

OF

ROBERT B. HEVERT

ON BEHALF OF TAMPA ELECTRIC COMPANY

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Constant Growth Discounted Cash Flow Model - Mr. Hevert's Proxy Group
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
American Electric Power Company, Inc.	AEP	$1.96	$45.10	4.35%	4.43%	3.56%	3.82%	4.50%	3.96%	7.98%	8.39%	8.94%
Cleco Corp.	CNL	$1.45	$45.75	3.17%	3.28%	8.00%	8.00%	5.50%	7.17%	8.76%	10.45%	11.30%
Empire District Electric	EDE	$1.00	$22.15	4.51%	4.60%	3.00%	3.00%	5.00%	3.67%	7.58%	8.26%	9.63%
Great Plains Energy Inc.	GXP	$0.87	$22.71	3.83%	3.95%	6.19%	6.26%	6.50%	6.32%	10.14%	10.27%	10.45%
IDACORP, Inc.	IDA	$1.52	$48.15	3.16%	3.21%	4.00%	4.00%	2.00%	3.33%	5.19%	6.54%	7.22%
Otter Tail Corporation	OTTR	$1.19	$28.25	4.21%	4.45%	6.00%	6.00%	21.50%	11.17%	10.34%	15.61%	26.16%
Pinnacle West Capital Corp.	PNW	$2.18	$55.72	3.91%	4.01%	4.45%	5.45%	5.00%	4.97%	8.45%	8.98%	9.47%
PNM Resources, Inc.	PNM	$0.66	$22.14	2.98%	3.11%	7.32%	6.43%	12.00%	8.58%	9.51%	11.69%	15.16%
Portland General Electric Company	POR	$1.10	$30.59	3.60%	3.69%	6.53%	5.34%	3.50%	5.12%	7.16%	8.81%	10.24%
Southern Company	SO	$2.03	$43.98	4.62%	4.72%	4.61%	4.67%	4.50%	4.59%	9.22%	9.32%	9.39%
Westar Energy, Inc.	WR	$1.36	$31.50	4.32%	4.42%	4.31%	3.90%	6.00%	4.74%	8.30%	9.16%	10.45%
PROXY GROUP MEAN				3.88%	3.99%	5.27%	5.17%	6.91%	5.78%	8.42%	9.77%	11.67%
PROXY GROUP MEDIAN				3.91%	4.01%	4.61%	5.34%	5.00%	4.97%	8.45%	9.16%	10.24%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of July 12, 2013
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

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Constant Growth Discounted Cash Flow Model - Mr. Hevert's Proxy Group
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
American Electric Power Company, Inc.	AEP	$1.96	$47.65	4.11%	4.19%	3.56%	3.82%	4.50%	3.96%	7.75%	8.15%	8.71%
Cleco Corp.	CNL	$1.45	$46.46	3.12%	3.23%	8.00%	8.00%	5.50%	7.17%	8.71%	10.40%	11.25%
Empire District Electric	EDE	$1.00	$22.30	4.48%	4.57%	3.00%	3.00%	5.00%	3.67%	7.55%	8.23%	9.60%
Great Plains Energy Inc.	GXP	$0.87	$23.14	3.76%	3.88%	6.19%	6.26%	6.50%	6.32%	10.07%	10.20%	10.38%
IDACORP, Inc.	IDA	$1.52	$48.10	3.16%	3.21%	4.00%	4.00%	2.00%	3.33%	5.19%	6.55%	7.22%
Otter Tail Corporation	OTTR	$1.19	$29.65	4.01%	4.24%	6.00%	6.00%	21.50%	11.17%	10.13%	15.40%	25.94%
Pinnacle West Capital Corp.	PNW	$2.18	$57.67	3.78%	3.87%	4.45%	5.45%	5.00%	4.97%	8.31%	8.84%	9.33%
PNM Resources, Inc.	PNM	$0.66	$22.83	2.89%	3.01%	7.32%	6.43%	12.00%	8.58%	9.41%	11.60%	15.06%
Portland General Electric Company	POR	$1.10	$30.86	3.56%	3.66%	6.53%	5.34%	3.50%	5.12%	7.13%	8.78%	10.21%
Southern Company	SO	$2.03	$45.72	4.44%	4.54%	4.61%	4.67%	4.50%	4.59%	9.04%	9.14%	9.21%
Westar Energy, Inc.	WR	$1.36	$32.62	4.17%	4.27%	4.31%	3.90%	6.00%	4.74%	8.15%	9.01%	10.29%
PROXY GROUP MEAN				3.77%	3.88%	5.27%	5.17%	6.91%	5.78%	8.31%	9.66%	11.57%
PROXY GROUP MEDIAN				3.78%	3.88%	4.61%	5.34%	5.00%	4.97%	8.31%	9.01%	10.21%

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Constant Growth Discounted Cash Flow Model - Mr. Hevert's Proxy Group
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
American Electric Power Company, Inc.	AEP	$1.96	$45.68	4.29%	4.38%	3.56%	3.82%	4.50%	3.96%	7.93%	8.34%	8.89%
Cleco Corp.	CNL	$1.45	$44.02	3.29%	3.41%	8.00%	8.00%	5.50%	7.17%	8.88%	10.58%	11.43%
Empire District Electric	EDE	$1.00	$21.57	4.64%	4.72%	3.00%	3.00%	5.00%	3.67%	7.71%	8.39%	9.75%
Great Plains Energy Inc.	GXP	$0.87	$22.08	3.94%	4.06%	6.19%	6.26%	6.50%	6.32%	10.25%	10.38%	10.57%
IDACORP, Inc.	IDA	$1.52	$46.17	3.29%	3.35%	4.00%	4.00%	2.00%	3.33%	5.33%	6.68%	7.36%
Otter Tail Corporation	OTTR	$1.19	$27.63	4.31%	4.55%	6.00%	6.00%	21.50%	11.17%	10.44%	15.71%	26.27%
Pinnacle West Capital Corp.	PNW	$2.18	$55.00	3.96%	4.06%	4.45%	5.45%	5.00%	4.97%	8.50%	9.03%	9.52%
PNM Resources, Inc.	PNM	$0.66	$21.99	3.00%	3.13%	7.32%	6.43%	12.00%	8.58%	9.53%	11.71%	15.18%
Portland General Electric Company	POR	$1.10	$29.24	3.76%	3.86%	6.53%	5.34%	3.50%	5.12%	7.33%	8.98%	10.42%
Southern Company	SO	$2.03	$44.77	4.53%	4.64%	4.61%	4.67%	4.50%	4.59%	9.14%	9.23%	9.31%
Westar Energy, Inc.	WR	$1.36	$31.01	4.39%	4.49%	4.31%	3.90%	6.00%	4.74%	8.37%	9.23%	10.52%
PROXY GROUP MEAN				3.95%	4.06%	5.27%	5.17%	6.91%	5.78%	8.49%	9.84%	11.75%
PROXY GROUP MEDIAN				3.96%	4.06%	4.61%	5.34%	5.00%	4.97%	8.50%	9.23%	10.42%

Notes:
[1] Source: Bloomberg Professional
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Constant Growth Discounted Cash Flow Model - Combined Proxy Group
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
American Electric Power Company, Inc.	AEP	$1.96	$45.10	4.35%	4.43%	3.56%	3.82%	4.50%	3.96%	7.98%	8.39%	8.94%
Black Hills Corporation	BKH	$1.52	$48.50	3.13%	3.26%	6.00%	6.00%	11.50%	7.83%	9.23%	11.09%	14.81%
Cleco Corporation	CNL	$1.45	$45.75	3.17%	3.28%	8.00%	8.00%	5.50%	7.17%	8.76%	10.45%	11.30%
CMS Energy Corporation	CMS	$1.02	$27.02	3.78%	3.89%	6.10%	5.87%	5.50%	5.82%	9.38%	9.71%	9.99%
Consolidated Edison, Inc.	ED	$2.46	$57.50	4.28%	4.33%	3.27%	1.71%	2.50%	2.49%	6.03%	6.83%	7.62%
Dominion Resources, Inc.	D	$2.25	$56.19	4.00%	4.13%	5.89%	6.98%	6.00%	6.29%	10.01%	10.42%	11.12%
Empire District Electric Company	EDE	$1.00	$22.15	4.51%	4.60%	3.00%	3.00%	5.00%	3.67%	7.58%	8.26%	9.63%
Great Plains Energy Inc.	GXP	$0.87	$22.71	3.83%	3.95%	6.19%	6.26%	6.50%	6.32%	10.14%	10.27%	10.45%
Hawaiian Electric Industries, Inc.	HE	$1.24	$25.09	4.94%	5.04%	3.70%	2.40%	5.50%	3.87%	7.40%	8.90%	10.58%
IDACORP, Inc.	IDA	$1.52	$48.15	3.16%	3.21%	4.00%	4.00%	2.00%	3.33%	5.19%	6.54%	7.22%
Otter Tail Corporation	OTTR	$1.19	$28.25	4.21%	4.45%	6.00%	6.00%	21.50%	11.17%	10.34%	15.61%	26.16%
Pepco Holdings, Inc.	POM	$1.08	$20.11	5.37%	5.52%	5.80%	4.26%	6.00%	5.35%	9.75%	10.87%	11.53%
Pinnacle West Capital Corporation	PNW	$2.18	$55.72	3.91%	4.01%	4.45%	5.45%	5.00%	4.97%	8.45%	8.98%	9.47%
PNM Resources, Inc.	PNM	$0.66	$22.14	2.98%	3.11%	7.32%	6.43%	12.00%	8.58%	9.51%	11.69%	15.16%
Portland General Electric Company	POR	$1.10	$30.59	3.60%	3.69%	6.53%	5.34%	3.50%	5.12%	7.16%	8.81%	10.24%
SCANA Corporation	SCG	$2.03	$49.34	4.11%	4.21%	4.65%	4.80%	4.50%	4.65%	8.71%	8.86%	9.01%
Southern Company	SO	$2.03	$43.98	4.62%	4.72%	4.61%	4.67%	4.50%	4.59%	9.22%	9.32%	9.39%
UIL Holdings Corporation	UIL	$1.73	$38.52	4.49%	4.63%	6.50%	8.06%	4.00%	6.19%	8.58%	10.81%	12.73%
UniSource Energy Corporation	UNS	$1.74	$46.10	3.77%	3.91%	6.30%	8.00%	6.50%	6.93%	10.19%	10.84%	11.93%
Westar Energy, Inc.	WR	$1.36	$31.50	4.32%	4.42%	4.31%	3.90%	6.00%	4.74%	8.30%	9.16%	10.45%
Wisconsin Energy Corporation	WEC	$1.36	$40.84	3.33%	3.42%	5.20%	4.89%	5.50%	5.20%	8.30%	8.61%	8.92%
PROXY GROUP MEAN				3.99%	4.10%	5.30%	5.23%	6.36%	5.63%	8.58%	9.73%	11.27%
PROXY GROUP MEDIAN				4.00%	4.13%	5.80%	5.34%	5.50%	5.20%	8.71%	9.32%	10.45%

Notes:
[1] Source: Bloomberg Professional
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[3] Equals [1] / [2]
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[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
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Constant Growth Discounted Cash Flow Model - Combined Proxy Group
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
American Electric Power Company, Inc.	AEP	$1.96	$47.65	4.11%	4.19%	3.56%	3.82%	4.50%	3.96%	7.75%	8.15%	8.71%
Black Hills Corporation	BKH	$1.52	$46.65	3.26%	3.39%	6.00%	6.00%	11.50%	7.83%	9.36%	11.22%	14.95%
Cleco Corporation	CNL	$1.45	$46.46	3.12%	3.23%	8.00%	8.00%	5.50%	7.17%	8.71%	10.40%	11.25%
CMS Energy Corporation	CMS	$1.02	$27.82	3.67%	3.77%	6.10%	5.87%	5.50%	5.82%	9.27%	9.60%	9.88%
Consolidated Edison, Inc.	ED	$2.46	$59.67	4.12%	4.17%	3.27%	1.71%	2.50%	2.49%	5.87%	6.67%	7.46%
Dominion Resources, Inc.	D	$2.25	$58.08	3.87%	4.00%	5.89%	6.98%	6.00%	6.29%	9.88%	10.29%	10.99%
Empire District Electric Company	EDE	$1.00	$22.30	4.48%	4.57%	3.00%	3.00%	5.00%	3.67%	7.55%	8.23%	9.60%
Great Plains Energy Inc.	GXP	$0.87	$23.14	3.76%	3.88%	6.19%	6.26%	6.50%	6.32%	10.07%	10.20%	10.38%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.66	4.65%	4.74%	3.70%	2.40%	5.50%	3.87%	7.11%	8.61%	10.28%
IDACORP, Inc.	IDA	$1.52	$48.10	3.16%	3.21%	4.00%	4.00%	2.00%	3.33%	5.19%	6.55%	7.22%
Otter Tail Corporation	OTTR	$1.19	$29.65	4.01%	4.24%	6.00%	6.00%	21.50%	11.17%	10.13%	15.40%	25.94%
Pepco Holdings, Inc.	POM	$1.08	$21.06	5.13%	5.26%	5.80%	4.26%	6.00%	5.35%	9.50%	10.62%	11.28%
Pinnacle West Capital Corporation	PNW	$2.18	$57.67	3.78%	3.87%	4.45%	5.45%	5.00%	4.97%	8.31%	8.84%	9.33%
PNM Resources, Inc.	PNM	$0.66	$22.83	2.89%	3.01%	7.32%	6.43%	12.00%	8.58%	9.41%	11.60%	15.06%
Portland General Electric Company	POR	$1.10	$30.86	3.56%	3.66%	6.53%	5.34%	3.50%	5.12%	7.13%	8.78%	10.21%
SCANA Corporation	SCG	$2.03	$50.89	3.99%	4.08%	4.65%	4.80%	4.50%	4.65%	8.58%	8.73%	8.88%
Southern Company	SO	$2.03	$45.72	4.44%	4.54%	4.61%	4.67%	4.50%	4.59%	9.04%	9.14%	9.21%
UIL Holdings Corporation	UIL	$1.73	$39.55	4.37%	4.50%	6.50%	8.06%	4.00%	6.19%	8.46%	10.69%	12.61%
UniSource Energy Corporation	UNS	$1.74	$47.85	3.64%	3.76%	6.30%	8.00%	6.50%	6.93%	10.05%	10.70%	11.78%
Westar Energy, Inc.	WR	$1.36	$32.62	4.17%	4.27%	4.31%	3.90%	6.00%	4.74%	8.15%	9.01%	10.29%
Wisconsin Energy Corporation	WEC	$1.36	$42.12	3.23%	3.31%	5.20%	4.89%	5.50%	5.20%	8.20%	8.51%	8.82%
PROXY GROUP MEAN				3.88%	3.98%	5.30%	5.23%	6.36%	5.63%	8.46%	9.61%	11.15%
PROXY GROUP MEDIAN				3.87%	4.00%	5.80%	5.34%	5.50%	5.20%	8.58%	9.14%	10.28%

Notes:
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[7] Source: Value Line
[8] Equals Average([5], [6], [7])
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Constant Growth Discounted Cash Flow Model - Combined Proxy Group
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
American Electric Power Company, Inc.	AEP	$1.96	$45.68	4.29%	4.38%	3.56%	3.82%	4.50%	3.96%	7.93%	8.34%	8.89%
Black Hills Corporation	BKH	$1.52	$42.13	3.61%	3.75%	6.00%	6.00%	11.50%	7.83%	9.72%	11.58%	15.31%
Cleco Corporation	CNL	$1.45	$44.02	3.29%	3.41%	8.00%	8.00%	5.50%	7.17%	8.88%	10.58%	11.43%
CMS Energy Corporation	CMS	$1.02	$26.29	3.88%	3.99%	6.10%	5.87%	5.50%	5.82%	9.49%	9.82%	10.10%
Consolidated Edison, Inc.	ED	$2.46	$58.16	4.23%	4.28%	3.27%	1.71%	2.50%	2.49%	5.98%	6.78%	7.57%
Dominion Resources, Inc.	D	$2.25	$55.34	4.07%	4.19%	5.89%	6.98%	6.00%	6.29%	10.08%	10.48%	11.19%
Empire District Electric Company	EDE	$1.00	$21.57	4.64%	4.72%	3.00%	3.00%	5.00%	3.67%	7.71%	8.39%	9.75%
Great Plains Energy Inc.	GXP	$0.87	$22.08	3.94%	4.06%	6.19%	6.26%	6.50%	6.32%	10.25%	10.38%	10.57%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.25	4.72%	4.82%	3.70%	2.40%	5.50%	3.87%	7.18%	8.68%	10.35%
IDACORP, Inc.	IDA	$1.52	$46.17	3.29%	3.35%	4.00%	4.00%	2.00%	3.33%	5.33%	6.68%	7.36%
Otter Tail Corporation	OTTR	$1.19	$27.63	4.31%	4.55%	6.00%	6.00%	21.50%	11.17%	10.44%	15.71%	26.27%
Pepco Holdings, Inc.	POM	$1.08	$20.34	5.31%	5.45%	5.80%	4.26%	6.00%	5.35%	9.68%	10.81%	11.47%
Pinnacle West Capital Corporation	PNW	$2.18	$55.00	3.96%	4.06%	4.45%	5.45%	5.00%	4.97%	8.50%	9.03%	9.52%
PNM Resources, Inc.	PNM	$0.66	$21.99	3.00%	3.13%	7.32%	6.43%	12.00%	8.58%	9.53%	11.71%	15.18%
Portland General Electric Company	POR	$1.10	$29.24	3.76%	3.86%	6.53%	5.34%	3.50%	5.12%	7.33%	8.98%	10.42%
SCANA Corporation	SCG	$2.03	$48.89	4.15%	4.25%	4.65%	4.80%	4.50%	4.65%	8.75%	8.90%	9.05%
Southern Company	SO	$2.03	$44.77	4.53%	4.64%	4.61%	4.67%	4.50%	4.59%	9.14%	9.23%	9.31%
UIL Holdings Corporation	UIL	$1.73	$37.96	4.55%	4.69%	6.50%	8.06%	4.00%	6.19%	8.64%	10.88%	12.80%
UniSource Energy Corporation	UNS	$1.74	$45.68	3.81%	3.94%	6.30%	8.00%	6.50%	6.93%	10.23%	10.87%	11.96%
Westar Energy, Inc.	WR	$1.36	$31.01	4.39%	4.49%	4.31%	3.90%	6.00%	4.74%	8.37%	9.23%	10.52%
Wisconsin Energy Corporation	WEC	$1.36	$40.15	3.39%	3.48%	5.20%	4.89%	5.50%	5.20%	8.36%	8.67%	8.98%
PROXY GROUP MEAN				4.05%	4.17%	5.30%	5.23%	6.36%	5.63%	8.64%	9.80%	11.33%
PROXY GROUP MEDIAN				4.07%	4.19%	5.80%	5.34%	5.50%	5.20%	8.75%	9.23%	10.42%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of July 12, 2013
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

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Multi-Stage Growth Discounted Cash Flow Model
Mr. Hevert's Proxy Group
30-Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
American Electric Power Company, Inc.	AEP	$ 45.10	3.56%	3.82%	4.50%	3.96%	5.59%	64.00%	61.00%	66.67%	$0.00	10.03%	15.01	2.69
Cleco Corp.	CNL	$ 45.75	8.00%	8.00%	5.50%	7.17%	5.59%	57.00%	57.00%	66.67%	$0.00	10.35%	13.99	2.50
Empire District Electric	EDE	$ 22.15	3.00%	3.00%	5.00%	3.67%	5.59%	72.00%	71.00%	66.67%	$0.00	9.65%	16.43	2.94
Great Plains Energy Inc.	GXP	$ 22.71	6.19%	6.26%	6.50%	6.32%	5.59%	56.00%	60.00%	66.67%	$0.00	10.17%	14.56	2.61
IDACORP, Inc.	IDA	$ 48.15	4.00%	4.00%	2.00%	3.33%	5.59%	48.00%	52.00%	66.67%	($0.00)	9.90%	15.45	2.77
Otter Tail Corporation	OTTR	$ 28.25	6.00%	6.00%	21.50%	11.17%	5.59%	89.00%	66.00%	66.67%	$0.00	9.66%	16.37	2.93
Pinnacle West Capital Corp.	PNW	$ 55.72	4.45%	5.45%	5.00%	4.97%	5.59%	62.00%	62.00%	66.67%	$0.00	10.09%	14.81	2.65
PNM Resources, Inc.	PNM	$ 22.14	7.32%	6.43%	12.00%	8.58%	5.59%	46.00%	51.00%	66.67%	$0.00	10.64%	13.20	2.36
Portland General Electric Company	POR	$ 30.59	6.53%	5.34%	3.50%	5.12%	5.59%	58.00%	59.00%	66.67%	$0.00	9.96%	15.26	2.73
Southern Company	SO	$ 43.98	4.61%	4.67%	4.50%	4.59%	5.59%	74.00%	70.00%	66.67%	($0.00)	9.99%	15.15	2.71
Westar Energy, Inc.	WR	$ 31.50	4.31%	3.90%	6.00%	4.74%	5.59%	61.00%	54.00%	66.67%	$0.00	10.30%	14.14	2.53
											MIN	9.65%		
											MEAN	10.07%		
											MAX	10.64%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2012	2013	2014	2015	2016	2017	**2018**	2019	2020	2021	2022	**2023**	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	$2.98	$3.10	$3.22	$3.35	$3.48	$3.62	$3.77	$3.94	$4.13	$4.34	$4.57	$4.82	$5.09	$5.38	$5.68	$6.00	$6.33
Cleco Corp.	CNL	$2.70	$2.89	$3.10	$3.32	$3.56	$3.82	$4.08	$4.35	$4.63	$4.91	$5.20	$5.49	$5.80	$6.12	$6.46	$6.82	$7.20
Empire District Electric	EDE	$1.32	$1.37	$1.42	$1.47	$1.52	$1.58	$1.64	$1.71	$1.79	$1.88	$1.98	$2.09	$2.21	$2.33	$2.46	$2.60	$2.75
Great Plains Energy Inc.	GXP	$1.35	$1.44	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.19	$2.32	$2.45	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39
IDACORP, Inc.	IDA	$3.37	$3.48	$3.60	$3.72	$3.84	$3.97	$4.12	$4.29	$4.48	$4.69	$4.94	$5.21	$5.51	$5.81	$6.14	$6.48	$6.84
Otter Tail Corporation	OTTR	$1.05	$1.17	$1.30	$1.44	$1.60	$1.78	$1.97	$2.15	$2.33	$2.50	$2.66	$2.81	$2.97	$3.14	$3.31	$3.50	$3.69
Pinnacle West Capital Corp.	PNW	$3.50	$3.67	$3.86	$4.05	$4.25	$4.46	$4.69	$4.93	$5.19	$5.47	$5.77	$6.09	$6.43	$6.79	$7.17	$7.57	$7.99
PNM Resources, Inc.	PNM	$1.31	$1.42	$1.54	$1.68	$1.82	$1.98	$2.14	$2.30	$2.46	$2.62	$2.78	$2.94	$3.10	$3.28	$3.46	$3.65	$3.86
Portland General Electric Company	POR	$1.87	$1.97	$2.07	$2.17	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$3.12	$3.29	$3.47	$3.67	$3.87	$4.09	$4.32
Southern Company	SO	$2.67	$2.79	$2.92	$3.06	$3.20	$3.34	$3.50	$3.67	$3.86	$4.06	$4.28	$4.52	$4.78	$5.04	$5.32	$5.62	$5.94
Westar Energy, Inc.	WR	$2.15	$2.25	$2.36	$2.47	$2.59	$2.71	$2.84	$2.98	$3.14	$3.31	$3.49	$3.68	$3.89	$4.10	$4.33	$4.57	$4.83

Projected Annual Dividend Payout Ratio		[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	64.00%	63.25%	62.50%	61.75%	61.00%	61.95%	62.89%	63.84%	64.78%	65.73%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Cleco Corp.	CNL	57.00%	57.00%	57.00%	57.00%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Empire District Electric	EDE	72.00%	71.75%	71.50%	71.25%	71.00%	70.28%	69.56%	68.84%	68.12%	67.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Great Plains Energy Inc.	GXP	56.00%	57.00%	58.00%	59.00%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
IDACORP, Inc.	IDA	48.00%	49.00%	50.00%	51.00%	52.00%	54.45%	56.89%	59.34%	61.78%	64.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Otter Tail Corporation	OTTR	89.00%	83.25%	77.50%	71.75%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pinnacle West Capital Corp.	PNW	62.00%	62.00%	62.00%	62.00%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
PNM Resources, Inc.	PNM	46.00%	47.25%	48.50%	49.75%	51.00%	53.61%	56.22%	58.84%	61.45%	64.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Portland General Electric Company	POR	58.00%	58.25%	58.50%	58.75%	59.00%	60.28%	61.56%	62.84%	64.12%	65.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Southern Company	SO	74.00%	73.00%	72.00%	71.00%	70.00%	69.45%	68.89%	68.34%	67.78%	67.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Westar Energy, Inc.	WR	61.00%	59.25%	57.50%	55.75%	54.00%	56.11%	58.22%	60.34%	62.45%	64.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%

Projected Annual Cash Flows	[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]

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Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
American Electric Power Company, Inc.	AEP	$1.98	$2.04	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$4.00	$95.01
Cleco Corp.	CNL	$1.65	$1.77	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$4.55	$100.79
Empire District Electric	EDE	$0.99	$1.02	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$1.73	$45.09
Great Plains Energy Inc.	GXP	$0.80	$0.87	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$2.14	$49.39
IDACORP, Inc.	IDA	$1.67	$1.76	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$4.32	$105.70
Otter Tail Corporation	OTTR	$1.04	$1.08	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$2.33	$60.44
Pinnacle West Capital Corp.	PNW	$2.28	$2.39	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$5.05	$118.35
PNM Resources, Inc.	PNM	$0.65	$0.73	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$2.44	$50.91
Portland General Electric Company	POR	$1.14	$1.20	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$2.73	$65.90
Southern Company	SO	$2.07	$2.13	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$3.75	$89.93
Westar Energy, Inc.	WR	$1.37	$1.40	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$3.05	$68.28

Projected Annual Data
Investor Cash Flows

		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	7/12/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
American Electric Power Company, Inc.	AEP	($45.10)	$0.00	$0.93	$2.02	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$99.01
Cleco Corp.	CNL	($45.75)	$0.00	$0.78	$1.71	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$105.34
Empire District Electric	EDE	($22.15)	$0.00	$0.46	$1.00	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$46.83
Great Plains Energy Inc.	GXP	($22.71)	$0.00	$0.38	$0.83	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$51.53
IDACORP, Inc.	IDA	($48.15)	$0.00	$0.79	$1.70	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$110.02
Otter Tail Corporation	OTTR	($28.25)	$0.00	$0.49	$1.10	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$62.77
Pinnacle West Capital Corp.	PNW	($55.72)	$0.00	$1.07	$2.33	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$123.40
PNM Resources, Inc.	PNM	($22.14)	$0.00	$0.31	$0.68	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$53.35
Portland General Electric Company	POR	($30.59)	$0.00	$0.54	$1.17	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$68.62
Southern Company	SO	($43.98)	$0.00	$0.97	$2.11	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$93.68
Westar Energy, Inc.	WR	($31.50)	$0.00	$0.65	$1.41	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$71.33

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Multi-Stage Growth Discounted Cash Flow Model
Mr. Hevert's Proxy Group
90-Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
American Electric Power Company, Inc.	AEP	$ 47.65	3.56%	3.82%	4.50%	3.96%	5.59%	64.00%	61.00%	66.67%	$0.00	9.79%	15.87	2.84
Cleco Corp.	CNL	$ 46.46	8.00%	8.00%	5.50%	7.17%	5.59%	57.00%	57.00%	66.67%	$0.00	10.28%	14.20	2.54
Empire District Electric	EDE	$ 22.30	3.00%	3.00%	5.00%	3.67%	5.59%	72.00%	71.00%	66.67%	$0.00	9.62%	16.54	2.96
Great Plains Energy Inc.	GXP	$ 23.14	6.19%	6.26%	6.50%	6.32%	5.59%	56.00%	60.00%	66.67%	$0.00	10.08%	14.82	2.65
IDACORP, Inc.	IDA	$ 48.10	4.00%	4.00%	2.00%	3.33%	5.59%	48.00%	52.00%	66.67%	($0.00)	9.91%	15.43	2.76
Otter Tail Corporation	OTTR	$ 29.65	6.00%	6.00%	21.50%	11.17%	5.59%	89.00%	66.00%	66.67%	$0.00	9.47%	17.18	3.08
Pinnacle West Capital Corp.	PNW	$ 57.67	4.45%	5.45%	5.00%	4.97%	5.59%	62.00%	62.00%	66.67%	$0.00	9.94%	15.33	2.74
PNM Resources, Inc.	PNM	$ 22.83	7.32%	6.43%	12.00%	8.58%	5.59%	46.00%	51.00%	66.67%	$0.00	10.49%	13.59	2.43
Portland General Electric Company	POR	$ 30.86	6.53%	5.34%	3.50%	5.12%	5.59%	58.00%	59.00%	66.67%	$0.00	9.92%	15.40	2.76
Southern Company	SO	$ 45.72	4.61%	4.67%	4.50%	4.59%	5.59%	74.00%	70.00%	66.67%	($0.00)	9.81%	15.77	2.82
Westar Energy, Inc.	WR	$ 32.62	4.31%	3.90%	6.00%	4.74%	5.59%	61.00%	54.00%	66.67%	$0.00	10.14%	14.64	2.62
											MIN	9.47%		
											MEAN	9.95%		
											MAX	10.49%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	$2.98	$3.10	$3.22	$3.35	$3.48	$3.62	$3.77	$3.94	$4.13	$4.34	$4.57	$4.82	$5.09	$5.38	$5.68	$6.00	$6.33
Cleco Corp.	CNL	$2.70	$2.89	$3.10	$3.32	$3.56	$3.82	$4.08	$4.35	$4.63	$4.91	$5.20	$5.49	$5.80	$6.12	$6.46	$6.82	$7.20
Empire District Electric	EDE	$1.32	$1.37	$1.42	$1.47	$1.52	$1.58	$1.64	$1.71	$1.79	$1.88	$1.98	$2.09	$2.21	$2.33	$2.46	$2.60	$2.75
Great Plains Energy Inc.	GXP	$1.35	$1.44	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.19	$2.32	$2.45	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39
IDACORP, Inc.	IDA	$3.37	$3.48	$3.60	$3.72	$3.84	$3.97	$4.12	$4.29	$4.48	$4.69	$4.94	$5.21	$5.51	$5.81	$6.14	$6.48	$6.84
Otter Tail Corporation	OTTR	$1.05	$1.17	$1.30	$1.44	$1.60	$1.78	$1.97	$2.15	$2.33	$2.50	$2.66	$2.81	$2.97	$3.14	$3.31	$3.50	$3.69
Pinnacle West Capital Corp.	PNW	$3.50	$3.67	$3.86	$4.05	$4.25	$4.46	$4.69	$4.93	$5.19	$5.47	$5.77	$6.09	$6.43	$6.79	$7.17	$7.57	$7.99
PNM Resources, Inc.	PNM	$1.31	$1.42	$1.54	$1.68	$1.82	$1.98	$2.14	$2.30	$2.46	$2.62	$2.78	$2.94	$3.10	$3.28	$3.46	$3.65	$3.86
Portland General Electric Company	POR	$1.87	$1.97	$2.07	$2.17	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$3.12	$3.29	$3.47	$3.67	$3.87	$4.09	$4.32
Southern Company	SO	$2.67	$2.79	$2.92	$3.06	$3.20	$3.34	$3.50	$3.67	$3.86	$4.06	$4.28	$4.52	$4.78	$5.04	$5.32	$5.62	$5.94
Westar Energy, Inc.	WR	$2.15	$2.25	$2.36	$2.47	$2.59	$2.71	$2.84	$2.98	$3.14	$3.31	$3.49	$3.68	$3.89	$4.10	$4.33	$4.57	$4.83

Projected Annual Dividend Payout Ratio		[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	64.00%	63.25%	62.50%	61.75%	61.00%	61.95%	62.89%	63.84%	64.78%	65.73%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Cleco Corp.	CNL	57.00%	57.00%	57.00%	57.00%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Empire District Electric	EDE	72.00%	71.75%	71.50%	71.25%	71.00%	70.28%	69.56%	68.84%	68.12%	67.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Great Plains Energy Inc.	GXP	56.00%	57.00%	58.00%	59.00%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
IDACORP, Inc.	IDA	48.00%	49.00%	50.00%	51.00%	52.00%	54.45%	56.89%	59.34%	61.78%	64.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Otter Tail Corporation	OTTR	89.00%	83.25%	77.50%	71.75%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pinnacle West Capital Corp.	PNW	62.00%	62.00%	62.00%	62.00%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
PNM Resources, Inc.	PNM	46.00%	47.25%	48.50%	49.75%	51.00%	53.61%	56.22%	58.84%	61.45%	64.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Portland General Electric Company	POR	58.00%	58.25%	58.50%	58.75%	59.00%	60.28%	61.56%	62.84%	64.12%	65.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Southern Company	SO	74.00%	73.00%	72.00%	71.00%	70.00%	69.45%	68.89%	68.34%	67.78%	67.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Westar Energy, Inc.	WR	61.00%	59.25%	57.50%	55.75%	54.00%	56.11%	58.22%	60.34%	62.45%	64.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%

Projected Annual Cash Flows		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]

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Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
American Electric Power Company, Inc.	AEP	$1.98	$2.04	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$4.00	$100.48
Cleco Corp.	CNL	$1.65	$1.77	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$4.55	$102.31
Empire District Electric	EDE	$0.99	$1.02	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$1.73	$45.41
Great Plains Energy Inc.	GXP	$0.80	$0.87	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$2.14	$50.29
IDACORP, Inc.	IDA	$1.67	$1.76	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$4.32	$105.60
Otter Tail Corporation	OTTR	$1.04	$1.08	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$2.33	$63.43
Pinnacle West Capital Corp.	PNW	$2.28	$2.39	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$5.05	$122.53
PNM Resources, Inc.	PNM	$0.65	$0.73	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$2.44	$52.41
Portland General Electric Company	POR	$1.14	$1.20	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$2.73	$66.48
Southern Company	SO	$2.07	$2.13	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$3.75	$93.64
Westar Energy, Inc.	WR	$1.37	$1.40	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$3.05	$70.68

Projected Annual Data
Investor Cash Flows

		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	7/12/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
American Electric Power Company, Inc.	AEP	($47.65)	$0.00	$0.93	$2.02	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$104.48
Cleco Corp.	CNL	($46.46)	$0.00	$0.78	$1.71	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$106.86
Empire District Electric	EDE	($22.30)	$0.00	$0.46	$1.00	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$47.14
Great Plains Energy Inc.	GXP	($23.13)	$0.00	$0.38	$0.83	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$52.43
IDACORP, Inc.	IDA	($48.10)	$0.00	$0.79	$1.70	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$109.92
Otter Tail Corporation	OTTR	($29.65)	$0.00	$0.49	$1.10	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$65.76
Pinnacle West Capital Corp.	PNW	($57.67)	$0.00	$1.07	$2.33	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$127.58
PNM Resources, Inc.	PNM	($22.83)	$0.00	$0.31	$0.68	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$54.85
Portland General Electric Company	POR	($30.86)	$0.00	$0.54	$1.17	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$69.21
Southern Company	SO	($45.72)	$0.00	$0.97	$2.11	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$97.38
Westar Energy, Inc.	WR	($32.62)	$0.00	$0.65	$1.41	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$73.73

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Multi-Stage Growth Discounted Cash Flow Model
Mr. Hevert's Proxy Group
180-Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
American Electric Power Company, Inc.	AEP	$ 45.68	3.56%	3.82%	4.50%	3.96%	5.59%	64.00%	61.00%	66.67%	$0.00	9.97%	15.20	2.72
Cleco Corp.	CNL	$ 44.02	8.00%	8.00%	5.50%	7.17%	5.59%	57.00%	57.00%	66.67%	($0.00)	10.53%	13.48	2.41
Empire District Electric	EDE	$ 21.57	3.00%	3.00%	5.00%	3.67%	5.59%	72.00%	71.00%	66.67%	($0.00)	9.76%	15.97	2.86
Great Plains Energy Inc.	GXP	$ 22.08	6.19%	6.26%	6.50%	6.32%	5.59%	56.00%	60.00%	66.67%	$0.00	10.30%	14.16	2.53
IDACORP, Inc.	IDA	$ 46.17	4.00%	4.00%	2.00%	3.33%	5.59%	48.00%	52.00%	66.67%	($0.00)	10.08%	14.82	2.65
Otter Tail Corporation	OTTR	$ 27.63	6.00%	6.00%	21.50%	11.17%	5.59%	89.00%	66.00%	66.67%	($0.00)	9.75%	16.01	2.87
Pinnacle West Capital Corp.	PNW	$ 55.00	4.45%	5.45%	5.00%	4.97%	5.59%	62.00%	62.00%	66.67%	$0.00	10.15%	14.62	2.62
PNM Resources, Inc.	PNM	$ 21.99	7.32%	6.43%	12.00%	8.58%	5.59%	46.00%	51.00%	66.67%	$0.00	10.67%	13.11	2.35
Portland General Electric Company	POR	$ 29.24	6.53%	5.34%	3.50%	5.12%	5.59%	58.00%	59.00%	66.67%	$0.00	10.16%	14.59	2.61
Southern Company	SO	$ 44.77	4.61%	4.67%	4.50%	4.59%	5.59%	74.00%	70.00%	66.67%	($0.00)	9.91%	15.44	2.76
Westar Energy, Inc.	WR	$ 31.01	4.31%	3.90%	6.00%	4.74%	5.59%	61.00%	54.00%	66.67%	$0.00	10.38%	13.92	2.49
											MIN	9.75%		
											MEAN	10.15%		
											MAX	10.67%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2012	2013	2014	2015	2016	2017	**2018**	2019	2020	2021	2022	**2023**	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	$2.98	$3.10	$3.22	$3.35	$3.48	$3.62	$3.77	$3.94	$4.13	$4.34	$4.57	$4.82	$5.09	$5.38	$5.68	$6.00	$6.33
Cleco Corp.	CNL	$2.70	$2.89	$3.10	$3.32	$3.56	$3.82	$4.08	$4.35	$4.63	$4.91	$5.20	$5.49	$5.80	$6.12	$6.46	$6.82	$7.20
Empire District Electric	EDE	$1.32	$1.37	$1.42	$1.47	$1.52	$1.58	$1.64	$1.71	$1.79	$1.88	$1.98	$2.09	$2.21	$2.33	$2.46	$2.60	$2.75
Great Plains Energy Inc.	GXP	$1.35	$1.44	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.19	$2.32	$2.45	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39
IDACORP, Inc.	IDA	$3.37	$3.48	$3.60	$3.72	$3.84	$3.97	$4.12	$4.29	$4.48	$4.69	$4.94	$5.21	$5.51	$5.81	$6.14	$6.48	$6.84
Otter Tail Corporation	OTTR	$1.05	$1.17	$1.30	$1.44	$1.60	$1.78	$1.97	$2.15	$2.33	$2.50	$2.66	$2.81	$2.97	$3.14	$3.31	$3.50	$3.69
Pinnacle West Capital Corp.	PNW	$3.50	$3.67	$3.86	$4.05	$4.25	$4.46	$4.69	$4.93	$5.19	$5.47	$5.77	$6.09	$6.43	$6.79	$7.17	$7.57	$7.99
PNM Resources, Inc.	PNM	$1.31	$1.42	$1.54	$1.68	$1.82	$1.98	$2.14	$2.30	$2.46	$2.62	$2.78	$2.94	$3.10	$3.28	$3.46	$3.65	$3.86
Portland General Electric Company	POR	$1.87	$1.97	$2.07	$2.17	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$3.12	$3.29	$3.47	$3.67	$3.87	$4.09	$4.32
Southern Company	SO	$2.67	$2.79	$2.92	$3.06	$3.20	$3.34	$3.50	$3.67	$3.86	$4.06	$4.28	$4.52	$4.78	$5.04	$5.32	$5.62	$5.94
Westar Energy, Inc.	WR	$2.15	$2.25	$2.36	$2.47	$2.59	$2.71	$2.84	$2.98	$3.14	$3.31	$3.49	$3.68	$3.89	$4.10	$4.33	$4.57	$4.83

Projected Annual Dividend Payout Ratio		[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	64.00%	63.25%	62.50%	61.75%	61.00%	61.95%	62.89%	63.84%	64.78%	65.73%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Cleco Corp.	CNL	57.00%	57.00%	57.00%	57.00%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Empire District Electric	EDE	72.00%	71.75%	71.50%	71.25%	71.00%	70.28%	69.56%	68.84%	68.12%	67.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Great Plains Energy Inc.	GXP	56.00%	57.00%	58.00%	59.00%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
IDACORP, Inc.	IDA	48.00%	49.00%	50.00%	51.00%	52.00%	54.45%	56.89%	59.34%	61.78%	64.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Otter Tail Corporation	OTTR	89.00%	83.25%	77.50%	71.75%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pinnacle West Capital Corp.	PNW	62.00%	62.00%	62.00%	62.00%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
PNM Resources, Inc.	PNM	46.00%	47.25%	48.50%	49.75%	51.00%	53.61%	56.22%	58.84%	61.45%	64.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Portland General Electric Company	POR	58.00%	58.25%	58.50%	58.75%	59.00%	60.28%	61.56%	62.84%	64.12%	65.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Southern Company	SO	74.00%	73.00%	72.00%	71.00%	70.00%	69.45%	68.89%	68.34%	67.78%	67.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Westar Energy, Inc.	WR	61.00%	59.25%	57.50%	55.75%	54.00%	56.11%	58.22%	60.34%	62.45%	64.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%

Projected Annual Cash Flows		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]

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Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
American Electric Power Company, Inc.	AEP	$1.98	$2.04	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$4.00	$96.25
Cleco Corp.	CNL	$1.65	$1.77	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$4.55	$97.07
Empire District Electric	EDE	$0.99	$1.02	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$1.73	$43.85
Great Plains Energy Inc.	GXP	$0.80	$0.87	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$2.14	$48.03
IDACORP, Inc.	IDA	$1.67	$1.76	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$4.32	$101.43
Otter Tail Corporation	OTTR	$1.04	$1.08	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$2.33	$59.11
Pinnacle West Capital Corp.	PNW	$2.28	$2.39	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$5.05	$116.81
PNM Resources, Inc.	PNM	$0.65	$0.73	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$2.44	$50.58
Portland General Electric Company	POR	$1.14	$1.20	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$2.73	$62.99
Southern Company	SO	$2.07	$2.13	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$3.75	$91.62
Westar Energy, Inc.	WR	$1.37	$1.40	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$3.05	$67.22

Projected Annual Data
Investor Cash Flows

		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	7/12/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
American Electric Power Company, Inc.	AEP	($45.67)	$0.00	$0.93	$2.02	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$100.25
Cleco Corp.	CNL	($44.02)	$0.00	$0.78	$1.71	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$101.62
Empire District Electric	EDE	($21.57)	$0.00	$0.46	$1.00	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$45.59
Great Plains Energy Inc.	GXP	($22.08)	$0.00	$0.38	$0.83	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$50.17
IDACORP, Inc.	IDA	($46.17)	$0.00	$0.79	$1.70	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$105.75
Otter Tail Corporation	OTTR	($27.63)	$0.00	$0.49	$1.10	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$61.45
Pinnacle West Capital Corp.	PNW	($55.00)	$0.00	$1.07	$2.33	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$121.86
PNM Resources, Inc.	PNM	($21.99)	$0.00	$0.31	$0.68	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$53.02
Portland General Electric Company	POR	($29.24)	$0.00	$0.54	$1.17	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$65.72
Southern Company	SO	($44.77)	$0.00	$0.97	$2.11	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$95.37
Westar Energy, Inc.	WR	($31.01)	$0.00	$0.65	$1.41	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$70.27

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Multi-Stage Growth Discounted Cash Flow Model
Combined Proxy Group
30-Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
American Electric Power Company, Inc.	AEP	$ 45.10	3.56%	3.82%	4.50%	3.96%	5.59%	64.00%	61.00%	66.67%	$0.00	10.03%	15.01	2.69
Black Hills Corporation	BKH	$ 48.50	6.00%	6.00%	11.50%	7.83%	5.59%	66.00%	56.00%	66.67%	$0.00	9.06%	19.21	3.44
Cleco Corporation	CNL	$ 45.75	8.00%	8.00%	5.50%	7.17%	5.59%	57.00%	57.00%	66.67%	($0.00)	10.35%	13.99	2.50
CMS Energy Corporation	CMS	$ 27.02	6.10%	5.87%	5.50%	5.82%	5.59%	60.00%	62.00%	66.67%	$0.00	9.86%	15.60	2.79
Consolidated Edison, Inc.	ED	$ 57.50	3.27%	1.71%	2.50%	2.49%	5.59%	63.00%	60.00%	66.67%	$0.00	9.67%	16.32	2.92
Dominion Resources, Inc.	D	$ 56.19	5.89%	6.98%	6.00%	6.29%	5.59%	70.00%	68.00%	66.67%	$0.00	9.49%	17.10	3.06
Empire District Electric Company	EDE	$ 22.15	3.00%	3.00%	5.00%	3.67%	5.59%	72.00%	71.00%	66.67%	$0.00	9.65%	16.43	2.94
Great Plains Energy Inc.	GXP	$ 22.71	6.19%	6.26%	6.50%	6.32%	5.59%	56.00%	60.00%	66.67%	$0.00	10.17%	14.56	2.61
Hawaiian Electric Industries, Inc.	HE	$ 25.09	3.70%	2.40%	5.50%	3.87%	5.59%	78.00%	72.00%	66.67%	($0.00)	10.29%	14.18	2.54
IDACORP, Inc.	IDA	$ 48.15	4.00%	4.00%	2.00%	3.33%	5.59%	48.00%	52.00%	66.67%	$0.00	9.90%	15.45	2.77
Otter Tail Corporation	OTTR	$ 28.25	6.00%	6.00%	21.50%	11.17%	5.59%	89.00%	66.00%	66.67%	($0.00)	9.66%	16.37	2.93
Pepco Holdings, Inc.	POM	$ 20.11	5.80%	4.26%	6.00%	5.35%	5.59%	93.00%	69.00%	66.67%	($0.00)	10.40%	13.85	2.48
Pinnacle West Capital Corporation	PNW	$ 55.72	4.45%	5.45%	5.00%	4.97%	5.59%	62.00%	62.00%	66.67%	($0.00)	10.09%	14.81	2.65
PNM Resources, Inc.	PNM	$ 22.14	7.32%	6.43%	12.00%	8.58%	5.59%	46.00%	51.00%	66.67%	($0.00)	10.64%	13.20	2.36
Portland General Electric Company	POR	$ 30.59	6.53%	5.34%	3.50%	5.12%	5.59%	58.00%	59.00%	66.67%	$0.00	9.96%	15.26	2.73
SCANA Corporation	SCG	$ 49.34	4.65%	4.80%	4.50%	4.65%	5.59%	60.00%	57.00%	66.67%	$0.00	10.00%	15.10	2.70
Southern Company	SO	$ 43.98	4.61%	4.67%	4.50%	4.59%	5.59%	74.00%	70.00%	66.67%	$0.00	9.99%	15.15	2.71
UIL Holdings Corporation	UIL	$ 38.52	6.50%	8.06%	4.00%	6.19%	5.59%	80.00%	68.00%	66.67%	$0.00	9.79%	15.85	2.84
UniSource Energy Corporation	UNS	$ 46.10	6.30%	8.00%	6.50%	6.93%	5.59%	66.00%	60.00%	66.67%	($0.00)	9.46%	17.20	3.08
Westar Energy, Inc.	WR	$ 31.50	4.31%	3.90%	6.00%	4.74%	5.59%	61.00%	54.00%	66.67%	($0.00)	10.30%	14.14	2.53
Wisconsin Energy Corporation	WEC	$ 40.84	5.20%	4.89%	5.50%	5.20%	5.59%	56.00%	66.00%	66.67%	($0.08)	9.77%	15.94	2.85
											MIN	9.06%		
											MEAN	9.93%		
											MAX	10.64%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	$2.98	$3.10	$3.22	$3.35	$3.48	$3.62	$3.77	$3.94	$4.13	$4.34	$4.57	$4.82	$5.09	$5.38	$5.68	$6.00	$6.33
Black Hills Corporation	BKH	$1.97	$2.12	$2.29	$2.47	$2.66	$2.87	$3.09	$3.31	$3.53	$3.75	$3.97	$4.20	$4.43	$4.68	$4.94	$5.22	$5.51
Cleco Corporation	CNL	$2.70	$2.89	$3.10	$3.32	$3.56	$3.82	$4.08	$4.35	$4.63	$4.91	$5.20	$5.49	$5.80	$6.12	$6.46	$6.82	$7.20
CMS Energy Corporation	CMS	$1.53	$1.62	$1.71	$1.81	$1.92	$2.03	$2.15	$2.27	$2.40	$2.54	$2.68	$2.83	$2.99	$3.15	$3.33	$3.52	$3.71
Consolidated Edison, Inc.	ED	$3.86	$3.96	$4.05	$4.16	$4.26	$4.37	$4.50	$4.66	$4.84	$5.06	$5.32	$5.62	$5.93	$6.26	$6.61	$6.98	$7.37
Dominion Resources, Inc.	D	$2.75	$2.92	$3.11	$3.30	$3.51	$3.73	$3.96	$4.20	$4.45	$4.71	$4.98	$5.26	$5.55	$5.86	$6.19	$6.53	$6.90
Empire District Electric Company	EDE	$1.32	$1.37	$1.42	$1.47	$1.52	$1.58	$1.64	$1.71	$1.79	$1.88	$1.98	$2.09	$2.21	$2.33	$2.46	$2.60	$2.75
Great Plains Energy Inc.	GXP	$1.35	$1.44	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.19	$2.32	$2.45	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39
Hawaiian Electric Industries, Inc.	HE	$1.68	$1.74	$1.81	$1.88	$1.96	$2.03	$2.12	$2.21	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$3.18	$3.36	$3.54
IDACORP, Inc.	IDA	$3.37	$3.48	$3.60	$3.72	$3.84	$3.97	$4.12	$4.29	$4.48	$4.69	$4.94	$5.21	$5.51	$5.81	$6.14	$6.48	$6.84
Otter Tail Corporation	OTTR	$1.05	$1.17	$1.30	$1.44	$1.60	$1.78	$1.97	$2.15	$2.33	$2.50	$2.66	$2.81	$2.97	$3.14	$3.31	$3.50	$3.69
Pepco Holdings, Inc.	POM	$1.24	$1.31	$1.38	$1.45	$1.53	$1.61	$1.70	$1.79	$1.89	$1.99	$2.10	$2.22	$2.34	$2.47	$2.61	$2.76	$2.91
Pinnacle West Capital Corporation	PNW	$3.50	$3.67	$3.86	$4.05	$4.25	$4.46	$4.69	$4.93	$5.19	$5.47	$5.77	$6.09	$6.43	$6.79	$7.17	$7.57	$7.99
PNM Resources, Inc.	PNM	$1.31	$1.42	$1.54	$1.68	$1.82	$1.98	$2.14	$2.30	$2.46	$2.62	$2.78	$2.94	$3.10	$3.28	$3.46	$3.65	$3.86
Portland General Electric Company	POR	$1.87	$1.97	$2.07	$2.17	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$3.12	$3.29	$3.47	$3.67	$3.87	$4.09	$4.32
SCANA Corporation	SCG	$3.15	$3.30	$3.45	$3.61	$3.78	$3.95	$4.14	$4.35	$4.57	$4.81	$5.07	$5.36	$5.66	$5.97	$6.31	$6.66	$7.03
Southern Company	SO	$2.67	$2.79	$2.92	$3.06	$3.20	$3.34	$3.50	$3.67	$3.86	$4.06	$4.28	$4.52	$4.78	$5.04	$5.32	$5.62	$5.94
UIL Holdings Corporation	UIL	$2.02	$2.14	$2.28	$2.42	$2.57	$2.73	$2.89	$3.07	$3.25	$3.43	$3.63	$3.83	$4.05	$4.27	$4.51	$4.76	$5.03
UniSource Energy Corporation	UNS	$2.20	$2.35	$2.52	$2.69	$2.88	$3.08	$3.28	$3.50	$3.71	$3.94	$4.17	$4.40	$4.65	$4.91	$5.18	$5.47	$5.77
Westar Energy, Inc.	WR	$2.15	$2.25	$2.36	$2.47	$2.59	$2.71	$2.84	$2.98	$3.14	$3.31	$3.49	$3.68	$3.89	$4.10	$4.33	$4.57	$4.83
Wisconsin Energy Corporation	WEC	$2.35	$2.47	$2.60	$2.74	$2.88	$3.03	$3.19	$3.36	$3.54	$3.73	$3.94	$4.16	$4.39	$4.63	$4.89	$5.17	$5.45

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Multi-Stage Growth Discounted Cash Flow Model
Combined Proxy Group
30-Day Average Stock Price

Projected Annual Dividend Payout Ratio		[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	64.00%	63.25%	62.50%	61.75%	61.00%	61.95%	62.89%	63.84%	64.78%	65.73%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Black Hills Corporation	BKH	66.00%	63.50%	61.00%	58.50%	56.00%	57.78%	59.56%	61.34%	63.12%	64.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Cleco Corporation	CNL	57.00%	57.00%	57.00%	57.00%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
CMS Energy Corporation	CMS	60.00%	60.50%	61.00%	61.50%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Consolidated Edison, Inc.	ED	63.00%	62.25%	61.50%	60.75%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Dominion Resources, Inc.	D	70.00%	69.50%	69.00%	68.50%	68.00%	67.78%	67.56%	67.34%	67.12%	66.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Empire District Electric Company	EDE	72.00%	71.75%	71.50%	71.25%	71.00%	70.28%	69.56%	68.84%	68.12%	67.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Great Plains Energy Inc.	GXP	56.00%	57.00%	58.00%	59.00%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Hawaiian Electric Industries, Inc.	HE	78.00%	76.50%	75.00%	73.50%	72.00%	71.11%	70.22%	69.34%	68.45%	67.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
IDACORP, Inc.	IDA	48.00%	49.00%	50.00%	51.00%	52.00%	54.45%	56.89%	59.34%	61.78%	64.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Otter Tail Corporation	OTTR	89.00%	83.25%	77.50%	71.75%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pepco Holdings, Inc.	POM	93.00%	87.00%	81.00%	75.00%	69.00%	68.61%	68.22%	67.84%	67.45%	67.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pinnacle West Capital Corporation	PNW	62.00%	62.00%	62.00%	62.00%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
PNM Resources, Inc.	PNM	46.00%	47.25%	48.50%	49.75%	51.00%	53.61%	56.22%	58.84%	61.45%	64.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Portland General Electric Company	POR	58.00%	58.25%	58.50%	58.75%	59.00%	60.28%	61.56%	62.84%	64.12%	65.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
SCANA Corporation	SCG	60.00%	59.25%	58.50%	57.75%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Southern Company	SO	74.00%	73.00%	72.00%	71.00%	70.00%	69.45%	68.89%	68.34%	67.78%	67.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
UIL Holdings Corporation	UIL	80.00%	77.00%	74.00%	71.00%	68.00%	67.78%	67.56%	67.34%	67.12%	66.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
UniSource Energy Corporation	UNS	66.00%	64.50%	63.00%	61.50%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Westar Energy, Inc.	WR	61.00%	59.25%	57.50%	55.75%	54.00%	56.11%	58.22%	60.34%	62.45%	64.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Wisconsin Energy Corporation	WEC	56.00%	58.50%	61.00%	63.50%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%

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Multi-Stage Growth Discounted Cash Flow Model
Combined Proxy Group
30-Day Average Stock Price

Projected Annual Cash Flows		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
American Electric Power Company, Inc.	AEP	$1.98	$2.04	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$4.00	$95.01
Black Hills Corporation	BKH	$1.40	$1.45	$1.51	$1.56	$1.61	$1.78	$1.97	$2.16	$2.37	$2.58	$2.80	$2.95	$3.12	$3.29	$3.48	$105.80
Cleco Corporation	CNL	$1.65	$1.77	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$4.55	$100.80
CMS Energy Corporation	CMS	$0.97	$1.04	$1.11	$1.18	$1.26	$1.35	$1.44	$1.54	$1.65	$1.77	$1.89	$1.99	$2.10	$2.22	$2.34	$57.92
Consolidated Edison, Inc.	ED	$2.49	$2.52	$2.56	$2.59	$2.62	$2.75	$2.90	$3.07	$3.26	$3.49	$3.75	$3.96	$4.18	$4.41	$4.66	$120.35
Dominion Resources, Inc.	D	$2.05	$2.16	$2.28	$2.40	$2.54	$2.68	$2.84	$3.00	$3.16	$3.33	$3.50	$3.70	$3.91	$4.13	$4.36	$117.95
Empire District Electric Company	EDE	$0.99	$1.02	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$1.73	$45.09
Great Plains Energy Inc.	GXP	$0.80	$0.87	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$2.14	$49.39
Hawaiian Electric Industries, Inc.	HE	$1.36	$1.39	$1.41	$1.44	$1.46	$1.50	$1.55	$1.60	$1.66	$1.73	$1.80	$1.90	$2.01	$2.12	$2.24	$50.28
IDACORP, Inc.	IDA	$1.67	$1.76	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$4.32	$105.70
Otter Tail Corporation	OTTR	$1.04	$1.08	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$2.33	$60.44
Pepco Holdings, Inc.	POM	$1.21	$1.20	$1.17	$1.15	$1.11	$1.16	$1.22	$1.28	$1.34	$1.41	$1.48	$1.56	$1.65	$1.74	$1.84	$40.31
Pinnacle West Capital Corporation	PNW	$2.28	$2.39	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$5.05	$118.35
PNM Resources, Inc.	PNM	$0.65	$0.73	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$2.44	$50.92
Portland General Electric Company	POR	$1.14	$1.20	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$2.73	$65.90
SCANA Corporation	SCG	$1.98	$2.04	$2.11	$2.18	$2.25	$2.43	$2.62	$2.83	$3.05	$3.30	$3.57	$3.77	$3.98	$4.21	$4.44	$106.16
Southern Company	SO	$2.07	$2.13	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$3.75	$89.93
UIL Holdings Corporation	UIL	$1.72	$1.75	$1.79	$1.82	$1.85	$1.96	$2.07	$2.19	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$3.18	$79.74
UniSource Energy Corporation	UNS	$1.55	$1.62	$1.69	$1.77	$1.85	$2.01	$2.17	$2.35	$2.54	$2.73	$2.93	$3.10	$3.27	$3.45	$3.65	$99.32
Westar Energy, Inc.	WR	$1.37	$1.40	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$3.05	$68.28
Wisconsin Energy Corporation	WEC	$1.38	$1.52	$1.67	$1.83	$2.00	$2.11	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.26	$3.44	$86.95

Projected Annual Data Investor Cash Flows		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	7/12/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
American Electric Power Company, Inc.	AEP	($45.10)	$0.00	$0.93	$2.02	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$99.01
Black Hills Corporation	BKH	($48.50)	$0.00	$0.66	$1.46	$1.51	$1.56	$1.61	$1.78	$1.97	$2.16	$2.37	$2.58	$2.80	$2.95	$3.12	$3.29	$109.27
Cleco Corporation	CNL	($45.75)	$0.00	$0.78	$1.71	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$105.34
CMS Energy Corporation	CMS	($27.02)	$0.00	$0.46	$1.00	$1.11	$1.18	$1.26	$1.35	$1.44	$1.54	$1.65	$1.77	$1.89	$1.99	$2.10	$2.22	$60.26
Consolidated Edison, Inc.	ED	($57.50)	$0.00	$1.17	$2.52	$2.56	$2.59	$2.62	$2.75	$2.90	$3.07	$3.26	$3.49	$3.75	$3.96	$4.18	$4.41	$125.01
Dominion Resources, Inc.	D	($56.19)	$0.00	$0.96	$2.11	$2.28	$2.40	$2.54	$2.68	$2.84	$3.00	$3.16	$3.33	$3.50	$3.70	$3.91	$4.13	$122.31
Empire District Electric Company	EDE	($22.15)	$0.00	$0.46	$1.00	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$46.83
Great Plains Energy Inc.	GXP	($22.71)	$0.00	$0.38	$0.83	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$51.53
Hawaiian Electric Industries, Inc.	HE	($25.09)	$0.00	$0.64	$1.39	$1.41	$1.44	$1.46	$1.50	$1.55	$1.60	$1.66	$1.73	$1.80	$1.90	$2.01	$2.12	$52.52
IDACORP, Inc.	IDA	($48.15)	$0.00	$0.79	$1.70	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$110.02
Otter Tail Corporation	OTTR	($28.25)	$0.00	$0.49	$1.10	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$62.77
Pepco Holdings, Inc.	POM	($20.11)	$0.00	$0.57	$1.25	$1.17	$1.15	$1.11	$1.16	$1.22	$1.28	$1.34	$1.41	$1.48	$1.56	$1.65	$1.74	$42.14
Pinnacle West Capital Corporation	PNW	($55.72)	$0.00	$1.07	$2.33	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$123.40
PNM Resources, Inc.	PNM	($22.14)	$0.00	$0.31	$0.68	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$53.35
Portland General Electric Company	POR	($30.59)	$0.00	$0.54	$1.17	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$68.62
SCANA Corporation	SCG	($49.34)	$0.00	$0.93	$2.02	$2.11	$2.18	$2.25	$2.43	$2.62	$2.83	$3.05	$3.30	$3.57	$3.77	$3.98	$4.21	$110.60
Southern Company	SO	($43.98)	$0.00	$0.97	$2.11	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.86	$3.02	$3.18	$3.36	$3.55	$93.68
UIL Holdings Corporation	UIL	($38.52)	$0.00	$0.81	$1.77	$1.79	$1.82	$1.85	$1.96	$2.07	$2.19	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$82.92
UniSource Energy Corporation	UNS	($46.10)	$0.00	$0.73	$1.61	$1.69	$1.77	$1.85	$2.01	$2.17	$2.35	$2.54	$2.73	$2.93	$3.10	$3.27	$3.45	$102.97
Westar Energy, Inc.	WR	($31.50)	$0.00	$0.65	$1.41	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$71.33
Wisconsin Energy Corporation	WEC	($40.92)	$0.00	$0.65	$1.42	$1.67	$1.83	$2.00	$2.11	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.26	$90.39

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Multi-Stage Growth Discounted Cash Flow Model
Combined Proxy Group
90-Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
American Electric Power Company, Inc.	AEP	$ 47.65	3.56%	3.82%	4.50%	3.96%	5.59%	64.00%	61.00%	66.67%	$0.00	9.79%	15.87	2.84
Black Hills Corporation	BKH	$ 46.65	6.00%	6.00%	11.50%	7.83%	5.59%	66.00%	56.00%	66.67%	($0.00)	9.19%	18.49	3.31
Cleco Corporation	CNL	$ 46.46	8.00%	8.00%	5.50%	7.17%	5.59%	57.00%	57.00%	66.67%	$0.00	10.28%	14.20	2.54
CMS Energy Corporation	CMS	$ 27.82	6.10%	5.87%	5.50%	5.82%	5.59%	60.00%	62.00%	66.67%	$0.00	9.74%	16.06	2.88
Consolidated Edison, Inc.	ED	$ 59.67	3.27%	1.71%	2.50%	2.49%	5.59%	63.00%	60.00%	66.67%	$0.00	9.52%	16.95	3.03
Dominion Resources, Inc.	D	$ 58.08	5.89%	6.98%	6.00%	6.29%	5.59%	70.00%	68.00%	66.67%	$0.00	9.36%	17.69	3.17
Empire District Electric Company	EDE	$ 22.30	3.00%	3.00%	5.00%	3.67%	5.59%	72.00%	71.00%	66.67%	$0.00	9.62%	16.54	2.96
Great Plains Energy Inc.	GXP	$ 23.14	6.19%	6.26%	6.50%	6.32%	5.59%	56.00%	60.00%	66.67%	$0.00	10.08%	14.83	2.65
Hawaiian Electric Industries, Inc.	HE	$ 26.66	3.70%	2.40%	5.50%	3.87%	5.59%	78.00%	72.00%	66.67%	$0.00	10.00%	15.12	2.71
IDACORP, Inc.	IDA	$ 48.10	4.00%	4.00%	2.00%	3.33%	5.59%	48.00%	52.00%	66.67%	($0.00)	9.91%	15.43	2.76
Otter Tail Corporation	OTTR	$ 29.65	6.00%	6.00%	21.50%	11.17%	5.59%	89.00%	66.00%	66.67%	$0.00	9.47%	17.18	3.08
Pepco Holdings, Inc.	POM	$ 21.06	5.80%	4.26%	6.00%	5.35%	5.59%	93.00%	69.00%	66.67%	$0.00	10.17%	14.55	2.60
Pinnacle West Capital Corporation	PNW	$ 57.67	4.45%	5.45%	5.00%	4.97%	5.59%	62.00%	62.00%	66.67%	$0.00	9.94%	15.33	2.74
PNM Resources, Inc.	PNM	$ 22.83	7.32%	6.43%	12.00%	8.58%	5.59%	46.00%	51.00%	66.67%	$0.00	10.49%	13.59	2.43
Portland General Electric Company	POR	$ 30.86	6.53%	5.34%	3.50%	5.12%	5.59%	58.00%	59.00%	66.67%	$0.00	9.92%	15.40	2.76
SCANA Corporation	SCG	$ 50.89	4.65%	4.80%	4.50%	4.65%	5.59%	60.00%	57.00%	66.67%	$0.00	9.87%	15.57	2.79
Southern Company	SO	$ 45.72	4.61%	4.67%	4.50%	4.59%	5.59%	74.00%	70.00%	66.67%	$0.00	9.81%	15.77	2.82
UIL Holdings Corporation	UIL	$ 39.55	6.50%	8.06%	4.00%	6.19%	5.59%	80.00%	68.00%	66.67%	$0.00	9.68%	16.29	2.92
UniSource Energy Corporation	UNS	$ 47.85	6.30%	8.00%	6.50%	6.93%	5.59%	66.00%	60.00%	66.67%	$0.00	9.32%	17.85	3.20
Westar Energy, Inc.	WR	$ 32.62	4.31%	3.90%	6.00%	4.74%	5.59%	61.00%	54.00%	66.67%	$0.00	10.14%	14.64	2.62
Wisconsin Energy Corporation	WEC	$ 42.12	5.20%	4.89%	5.50%	5.20%	5.59%	56.00%	66.00%	66.67%	($0.08)	9.64%	16.44	2.94
											MIN	9.19%		
											MEAN	9.81%		
											MAX	10.49%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2012	2013	2014	2015	2016	2017	**2018**	2019	2020	2021	2022	**2023**	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	$2.98	$3.10	$3.22	$3.35	$3.48	$3.62	$3.77	$3.94	$4.13	$4.34	$4.57	$4.82	$5.09	$5.38	$5.68	$6.00	$6.33
Black Hills Corporation	BKH	$1.97	$2.12	$2.29	$2.47	$2.66	$2.87	$3.09	$3.31	$3.53	$3.75	$3.97	$4.20	$4.43	$4.68	$4.94	$5.22	$5.51
Cleco Corporation	CNL	$2.70	$2.89	$3.10	$3.32	$3.56	$3.82	$4.08	$4.35	$4.63	$4.91	$5.20	$5.49	$5.80	$6.12	$6.46	$6.82	$7.20
CMS Energy Corporation	CMS	$1.53	$1.62	$1.71	$1.81	$1.92	$2.03	$2.15	$2.27	$2.40	$2.54	$2.68	$2.83	$2.99	$3.15	$3.33	$3.52	$3.71
Consolidated Edison, Inc.	ED	$3.86	$3.96	$4.05	$4.16	$4.26	$4.37	$4.50	$4.66	$4.84	$5.06	$5.32	$5.62	$5.93	$6.26	$6.61	$6.98	$7.37
Dominion Resources, Inc.	D	$2.75	$2.92	$3.11	$3.30	$3.51	$3.73	$3.96	$4.20	$4.45	$4.71	$4.98	$5.26	$5.55	$5.86	$6.19	$6.53	$6.90
Empire District Electric Company	EDE	$1.32	$1.37	$1.42	$1.47	$1.52	$1.58	$1.64	$1.71	$1.79	$1.88	$1.98	$2.09	$2.21	$2.33	$2.46	$2.60	$2.75
Great Plains Energy Inc.	GXP	$1.35	$1.44	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.19	$2.32	$2.45	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39
Hawaiian Electric Industries, Inc.	HE	$1.68	$1.74	$1.81	$1.88	$1.96	$2.03	$2.12	$2.21	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$3.18	$3.36	$3.54
IDACORP, Inc.	IDA	$3.37	$3.48	$3.60	$3.72	$3.84	$3.97	$4.12	$4.29	$4.48	$4.69	$4.94	$5.21	$5.51	$5.81	$6.14	$6.48	$6.84
Otter Tail Corporation	OTTR	$1.05	$1.17	$1.30	$1.44	$1.60	$1.78	$1.97	$2.15	$2.33	$2.50	$2.66	$2.81	$2.97	$3.14	$3.31	$3.50	$3.69
Pepco Holdings, Inc.	POM	$1.24	$1.31	$1.38	$1.45	$1.53	$1.61	$1.70	$1.79	$1.89	$1.99	$2.10	$2.22	$2.34	$2.47	$2.61	$2.76	$2.91
Pinnacle West Capital Corporation	PNW	$3.50	$3.67	$3.86	$4.05	$4.25	$4.46	$4.69	$4.93	$5.19	$5.47	$5.77	$6.09	$6.43	$6.79	$7.17	$7.57	$7.99
PNM Resources, Inc.	PNM	$1.31	$1.42	$1.54	$1.68	$1.82	$1.98	$2.14	$2.30	$2.46	$2.62	$2.78	$2.94	$3.10	$3.28	$3.46	$3.65	$3.86
Portland General Electric Company	POR	$1.87	$1.97	$2.07	$2.17	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$3.12	$3.29	$3.47	$3.67	$3.87	$4.09	$4.32
SCANA Corporation	SCG	$3.15	$3.30	$3.45	$3.61	$3.78	$3.95	$4.14	$4.35	$4.57	$4.81	$5.07	$5.36	$5.66	$5.97	$6.31	$6.66	$7.03
Southern Company	SO	$2.67	$2.79	$2.92	$3.06	$3.20	$3.34	$3.50	$3.67	$3.86	$4.06	$4.28	$4.52	$4.78	$5.04	$5.32	$5.62	$5.94
UIL Holdings Corporation	UIL	$2.02	$2.14	$2.28	$2.42	$2.57	$2.73	$2.89	$3.07	$3.25	$3.43	$3.63	$3.83	$4.05	$4.27	$4.51	$4.76	$5.03
UniSource Energy Corporation	UNS	$2.20	$2.35	$2.52	$2.69	$2.88	$3.08	$3.28	$3.50	$3.71	$3.94	$4.17	$4.40	$4.65	$4.91	$5.18	$5.47	$5.77
Westar Energy, Inc.	WR	$2.15	$2.25	$2.36	$2.47	$2.59	$2.71	$2.84	$2.98	$3.14	$3.31	$3.49	$3.68	$3.89	$4.10	$4.33	$4.57	$4.83
Wisconsin Energy Corporation	WEC	$2.35	$2.47	$2.60	$2.74	$2.88	$3.03	$3.19	$3.36	$3.54	$3.73	$3.94	$4.16	$4.39	$4.63	$4.89	$5.17	$5.45

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Multi-Stage Growth Discounted Cash Flow Model
Combined Proxy Group
90-Day Average Stock Price

Projected Annual Dividend Payout Ratio		[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	64.00%	63.25%	62.50%	61.75%	61.00%	61.95%	62.89%	63.84%	64.78%	65.73%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Black Hills Corporation	BKH	66.00%	63.50%	61.00%	58.50%	56.00%	57.78%	59.56%	61.34%	63.12%	64.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Cleco Corporation	CNL	57.00%	57.00%	57.00%	57.00%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
CMS Energy Corporation	CMS	60.00%	60.50%	61.00%	61.50%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Consolidated Edison, Inc.	ED	63.00%	62.25%	61.50%	60.75%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Dominion Resources, Inc.	D	70.00%	69.50%	69.00%	68.50%	68.00%	67.78%	67.56%	67.34%	67.12%	66.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Empire District Electric Company	EDE	72.00%	71.75%	71.50%	71.25%	71.00%	70.28%	69.56%	68.84%	68.12%	67.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Great Plains Energy Inc.	GXP	56.00%	57.00%	58.00%	59.00%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Hawaiian Electric Industries, Inc.	HE	78.00%	76.50%	75.00%	73.50%	72.00%	71.11%	70.22%	69.34%	68.45%	67.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
IDACORP, Inc.	IDA	48.00%	49.00%	50.00%	51.00%	52.00%	54.45%	56.89%	59.34%	61.78%	64.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Otter Tail Corporation	OTTR	89.00%	83.25%	77.50%	71.75%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pepco Holdings, Inc.	POM	93.00%	87.00%	81.00%	75.00%	69.00%	68.61%	68.22%	67.84%	67.45%	67.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pinnacle West Capital Corporation	PNW	62.00%	62.00%	62.00%	62.00%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
PNM Resources, Inc.	PNM	46.00%	47.25%	48.50%	49.75%	51.00%	53.61%	56.22%	58.84%	61.45%	64.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Portland General Electric Company	POR	58.00%	58.25%	58.50%	58.75%	59.00%	60.28%	61.56%	62.84%	64.12%	65.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
SCANA Corporation	SCG	60.00%	59.25%	58.50%	57.75%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Southern Company	SO	74.00%	73.00%	72.00%	71.00%	70.00%	69.45%	68.89%	68.34%	67.78%	67.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
UIL Holdings Corporation	UIL	80.00%	77.00%	74.00%	71.00%	68.00%	67.78%	67.56%	67.34%	67.12%	66.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
UniSource Energy Corporation	UNS	66.00%	64.50%	63.00%	61.50%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Westar Energy, Inc.	WR	61.00%	59.25%	57.50%	55.75%	54.00%	56.11%	58.22%	60.34%	62.45%	64.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Wisconsin Energy Corporation	WEC	56.00%	58.50%	61.00%	63.50%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%

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Multi-Stage Growth Discounted Cash Flow Model
Combined Proxy Group
90-Day Average Stock Price

Projected Annual Cash Flows		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
American Electric Power Company, Inc.	AEP	$1.98	$2.04	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$4.00	$100.48
Black Hills Corporation	BKH	$1.40	$1.45	$1.51	$1.56	$1.61	$1.78	$1.97	$2.16	$2.37	$2.58	$2.80	$2.95	$3.12	$3.29	$3.48	$101.83
Cleco Corporation	CNL	$1.65	$1.77	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$4.55	$102.31
CMS Energy Corporation	CMS	$0.97	$1.04	$1.11	$1.18	$1.26	$1.35	$1.44	$1.54	$1.65	$1.77	$1.89	$1.99	$2.10	$2.22	$2.34	$59.64
Consolidated Edison, Inc.	ED	$2.49	$2.52	$2.56	$2.59	$2.62	$2.75	$2.90	$3.07	$3.26	$3.49	$3.75	$3.96	$4.18	$4.41	$4.66	$125.00
Dominion Resources, Inc.	D	$2.05	$2.16	$2.28	$2.40	$2.54	$2.68	$2.84	$3.00	$3.16	$3.33	$3.50	$3.70	$3.91	$4.13	$4.36	$122.00
Empire District Electric Company	EDE	$0.99	$1.02	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$1.73	$45.41
Great Plains Energy Inc.	GXP	$0.80	$0.87	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$2.14	$50.30
Hawaiian Electric Industries, Inc.	HE	$1.36	$1.39	$1.41	$1.44	$1.46	$1.50	$1.55	$1.60	$1.66	$1.73	$1.80	$1.90	$2.01	$2.12	$2.24	$53.61
IDACORP, Inc.	IDA	$1.67	$1.76	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$4.32	$105.60
Otter Tail Corporation	OTTR	$1.04	$1.08	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$2.33	$63.43
Pepco Holdings, Inc.	POM	$1.21	$1.20	$1.17	$1.15	$1.11	$1.16	$1.22	$1.28	$1.34	$1.41	$1.48	$1.56	$1.65	$1.74	$1.84	$42.35
Pinnacle West Capital Corporation	PNW	$2.28	$2.39	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$5.05	$122.53
PNM Resources, Inc.	PNM	$0.65	$0.73	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$2.44	$52.41
Portland General Electric Company	POR	$1.14	$1.20	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$2.73	$66.48
SCANA Corporation	SCG	$1.98	$2.04	$2.11	$2.18	$2.25	$2.43	$2.62	$2.83	$3.05	$3.30	$3.57	$3.77	$3.98	$4.21	$4.44	$109.50
Southern Company	SO	$2.07	$2.13	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$3.75	$93.64
UIL Holdings Corporation	UIL	$1.72	$1.75	$1.79	$1.82	$1.85	$1.96	$2.07	$2.19	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$3.18	$81.94
UniSource Energy Corporation	UNS	$1.55	$1.62	$1.69	$1.77	$1.85	$2.01	$2.17	$2.35	$2.54	$2.73	$2.93	$3.10	$3.27	$3.45	$3.65	$103.08
Westar Energy, Inc.	WR	$1.37	$1.40	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$3.05	$70.68
Wisconsin Energy Corporation	WEC	$1.38	$1.52	$1.67	$1.83	$2.00	$2.11	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.26	$3.44	$89.68

Projected Annual Data Investor Cash Flows		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	7/12/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
American Electric Power Company, Inc.	AEP	($47.65)	$0.00	$0.93	$2.02	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$104.48
Black Hills Corporation	BKH	($46.65)	$0.00	$0.66	$1.46	$1.51	$1.56	$1.61	$1.78	$1.97	$2.16	$2.37	$2.58	$2.80	$2.95	$3.12	$3.29	$105.31
Cleco Corporation	CNL	($46.46)	$0.00	$0.78	$1.71	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$106.86
CMS Energy Corporation	CMS	($27.82)	$0.00	$0.46	$1.00	$1.11	$1.18	$1.26	$1.35	$1.44	$1.54	$1.65	$1.77	$1.89	$1.99	$2.10	$2.22	$61.98
Consolidated Edison, Inc.	ED	($59.67)	$0.00	$1.17	$2.52	$2.56	$2.59	$2.62	$2.75	$2.90	$3.07	$3.26	$3.49	$3.75	$3.96	$4.18	$4.41	$129.65
Dominion Resources, Inc.	D	($58.08)	$0.00	$0.96	$2.11	$2.28	$2.40	$2.54	$2.68	$2.84	$3.00	$3.16	$3.33	$3.50	$3.70	$3.91	$4.13	$126.36
Empire District Electric Company	EDE	($22.30)	$0.00	$0.46	$1.00	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$47.14
Great Plains Energy Inc.	GXP	($23.14)	$0.00	$0.38	$0.83	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$52.44
Hawaiian Electric Industries, Inc.	HE	($26.66)	$0.00	$0.64	$1.39	$1.41	$1.44	$1.46	$1.50	$1.55	$1.60	$1.66	$1.73	$1.80	$1.90	$2.01	$2.12	$55.84
IDACORP, Inc.	IDA	($48.10)	$0.00	$0.79	$1.70	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$109.92
Otter Tail Corporation	OTTR	($29.65)	$0.00	$0.49	$1.10	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$65.76
Pepco Holdings, Inc.	POM	($21.06)	$0.00	$0.57	$1.25	$1.17	$1.15	$1.11	$1.16	$1.22	$1.28	$1.34	$1.41	$1.48	$1.56	$1.65	$1.74	$44.18
Pinnacle West Capital Corporation	PNW	($57.67)	$0.00	$1.07	$2.33	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$127.58
PNM Resources, Inc.	PNM	($22.83)	$0.00	$0.31	$0.68	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$54.85
Portland General Electric Company	POR	($30.86)	$0.00	$0.54	$1.17	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$69.21
SCANA Corporation	SCG	($50.89)	$0.00	$0.93	$2.02	$2.11	$2.18	$2.25	$2.43	$2.62	$2.83	$3.05	$3.30	$3.57	$3.77	$3.98	$4.21	$113.94
Southern Company	SO	($45.72)	$0.00	$0.97	$2.11	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$97.38
UIL Holdings Corporation	UIL	($39.55)	$0.00	$0.81	$1.77	$1.79	$1.82	$1.85	$1.96	$2.07	$2.19	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$85.12
UniSource Energy Corporation	UNS	($47.85)	$0.00	$0.73	$1.61	$1.69	$1.77	$1.85	$2.01	$2.17	$2.35	$2.54	$2.73	$2.93	$3.10	$3.27	$3.45	$106.73
Westar Energy, Inc.	WR	($32.62)	$0.00	$0.65	$1.41	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$73.73
Wisconsin Energy Corporation	WEC	($42.20)	$0.00	$0.65	$1.42	$1.67	$1.83	$2.00	$2.11	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.26	$93.13

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Multi-Stage Growth Discounted Cash Flow Model
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180-Day Average Stock Price

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2013	2017	2023	Proof	IRR	P/E Ratio	PEG Ratio
American Electric Power Company, Inc.	AEP	$ 45.68	3.56%	3.82%	4.50%	3.96%	5.59%	64.00%	61.00%	66.67%	($0.00)	9.97%	15.20	2.72
Black Hills Corporation	BKH	$ 42.13	6.00%	6.00%	11.50%	7.83%	5.59%	66.00%	56.00%	66.67%	($0.00)	9.57%	16.73	2.99
Cleco Corporation	CNL	$ 44.02	8.00%	8.00%	5.50%	7.17%	5.59%	57.00%	57.00%	66.67%	($0.00)	10.53%	13.48	2.41
CMS Energy Corporation	CMS	$ 26.29	6.10%	5.87%	5.50%	5.82%	5.59%	60.00%	62.00%	66.67%	($0.00)	9.98%	15.18	2.72
Consolidated Edison, Inc.	ED	$ 58.16	3.27%	1.71%	2.50%	2.49%	5.59%	63.00%	60.00%	66.67%	($0.00)	9.62%	16.51	2.96
Dominion Resources, Inc.	D	$ 55.34	5.89%	6.98%	6.00%	6.29%	5.59%	70.00%	68.00%	66.67%	($0.00)	9.55%	16.84	3.01
Empire District Electric Company	EDE	$ 21.57	3.00%	3.00%	5.00%	3.67%	5.59%	72.00%	71.00%	66.67%	($0.00)	9.76%	15.97	2.86
Great Plains Energy Inc.	GXP	$ 22.08	6.19%	6.26%	6.50%	6.32%	5.59%	56.00%	60.00%	66.67%	($0.00)	10.30%	14.16	2.53
Hawaiian Electric Industries, Inc.	HE	$ 26.25	3.70%	2.40%	5.50%	3.87%	5.59%	78.00%	72.00%	66.67%	($0.00)	10.07%	14.88	2.66
IDACORP, Inc.	IDA	$ 46.17	4.00%	4.00%	2.00%	3.33%	5.59%	48.00%	52.00%	66.67%	($0.00)	10.08%	14.82	2.65
Otter Tail Corporation	OTTR	$ 27.63	6.00%	6.00%	21.50%	11.17%	5.59%	89.00%	66.00%	66.67%	($0.00)	9.75%	16.01	2.87
Pepco Holdings, Inc.	POM	$ 20.34	5.80%	4.26%	6.00%	5.35%	5.59%	93.00%	69.00%	66.67%	($0.00)	10.34%	14.02	2.51
Pinnacle West Capital Corporation	PNW	$ 55.00	4.45%	5.45%	5.00%	4.97%	5.59%	62.00%	62.00%	66.67%	($0.00)	10.15%	14.62	2.62
PNM Resources, Inc.	PNM	$ 21.99	7.32%	6.43%	12.00%	8.58%	5.59%	46.00%	51.00%	66.67%	($0.00)	10.67%	13.11	2.35
Portland General Electric Company	POR	$ 29.24	6.53%	5.34%	3.50%	5.12%	5.59%	58.00%	59.00%	66.67%	($0.00)	10.16%	14.59	2.61
SCANA Corporation	SCG	$ 48.89	4.65%	4.80%	4.50%	4.65%	5.59%	60.00%	57.00%	66.67%	($0.00)	10.04%	14.96	2.68
Southern Company	SO	$ 44.77	4.61%	4.67%	4.50%	4.59%	5.59%	74.00%	70.00%	66.67%	($0.00)	9.91%	15.44	2.76
UIL Holdings Corporation	UIL	$ 37.96	6.50%	8.06%	4.00%	6.19%	5.59%	80.00%	68.00%	66.67%	($0.00)	9.86%	15.62	2.80
UniSource Energy Corporation	UNS	$ 45.68	6.30%	8.00%	6.50%	6.93%	5.59%	66.00%	60.00%	66.67%	($0.00)	9.50%	17.05	3.05
Westar Energy, Inc.	WR	$ 31.01	4.31%	3.90%	6.00%	4.74%	5.59%	61.00%	54.00%	66.67%	($0.00)	10.38%	13.92	2.49
Wisconsin Energy Corporation	WEC	$ 40.15	5.20%	4.89%	5.50%	5.20%	5.59%	56.00%	66.00%	66.67%	($0.08)	9.84%	15.67	2.80
											MIN	9.50%		
											MEAN	10.00%		
											MAX	10.67%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2012	2013	2014	2015	2016	2017	**2018**	2019	2020	2021	2022	**2023**	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	$2.98	$3.10	$3.22	$3.35	$3.48	$3.62	$3.77	$3.94	$4.13	$4.34	$4.57	$4.82	$5.09	$5.38	$5.68	$6.00	$6.33
Black Hills Corporation	BKH	$1.97	$2.12	$2.29	$2.47	$2.66	$2.87	$3.09	$3.31	$3.53	$3.75	$3.97	$4.20	$4.43	$4.68	$4.94	$5.22	$5.51
Cleco Corporation	CNL	$2.70	$2.89	$3.10	$3.32	$3.56	$3.82	$4.08	$4.35	$4.63	$4.91	$5.20	$5.49	$5.80	$6.12	$6.46	$6.82	$7.20
CMS Energy Corporation	CMS	$1.53	$1.62	$1.71	$1.81	$1.92	$2.03	$2.15	$2.27	$2.40	$2.54	$2.68	$2.83	$2.99	$3.15	$3.33	$3.52	$3.71
Consolidated Edison, Inc.	ED	$3.86	$3.96	$4.05	$4.16	$4.26	$4.37	$4.50	$4.66	$4.84	$5.06	$5.32	$5.62	$5.93	$6.26	$6.61	$6.98	$7.37
Dominion Resources, Inc.	D	$2.75	$2.92	$3.11	$3.30	$3.51	$3.73	$3.96	$4.20	$4.45	$4.71	$4.98	$5.26	$5.55	$5.86	$6.19	$6.53	$6.90
Empire District Electric Company	EDE	$1.32	$1.37	$1.42	$1.47	$1.52	$1.58	$1.64	$1.71	$1.79	$1.88	$1.98	$2.09	$2.21	$2.33	$2.46	$2.60	$2.75
Great Plains Energy Inc.	GXP	$1.35	$1.44	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.19	$2.32	$2.45	$2.59	$2.73	$2.88	$3.04	$3.21	$3.39
Hawaiian Electric Industries, Inc.	HE	$1.68	$1.74	$1.81	$1.88	$1.96	$2.03	$2.12	$2.21	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$3.18	$3.36	$3.54
IDACORP, Inc.	IDA	$3.37	$3.48	$3.60	$3.72	$3.84	$3.97	$4.12	$4.29	$4.48	$4.69	$4.94	$5.21	$5.51	$5.81	$6.14	$6.48	$6.84
Otter Tail Corporation	OTTR	$1.05	$1.17	$1.30	$1.44	$1.60	$1.78	$1.97	$2.15	$2.33	$2.50	$2.66	$2.81	$2.97	$3.14	$3.31	$3.50	$3.69
Pepco Holdings, Inc.	POM	$1.24	$1.31	$1.38	$1.45	$1.53	$1.61	$1.70	$1.79	$1.89	$1.99	$2.10	$2.22	$2.34	$2.47	$2.61	$2.76	$2.91
Pinnacle West Capital Corporation	PNW	$3.50	$3.67	$3.86	$4.05	$4.25	$4.46	$4.69	$4.93	$5.19	$5.47	$5.77	$6.09	$6.43	$6.79	$7.17	$7.57	$7.99
PNM Resources, Inc.	PNM	$1.31	$1.42	$1.54	$1.68	$1.82	$1.98	$2.14	$2.30	$2.46	$2.62	$2.78	$2.94	$3.10	$3.28	$3.46	$3.65	$3.86
Portland General Electric Company	POR	$1.87	$1.97	$2.07	$2.17	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$3.12	$3.29	$3.47	$3.67	$3.87	$4.09	$4.32
SCANA Corporation	SCG	$3.15	$3.30	$3.45	$3.61	$3.78	$3.95	$4.14	$4.35	$4.57	$4.81	$5.07	$5.36	$5.66	$5.97	$6.31	$6.66	$7.03
Southern Company	SO	$2.67	$2.79	$2.92	$3.06	$3.20	$3.34	$3.50	$3.67	$3.86	$4.06	$4.28	$4.52	$4.78	$5.04	$5.32	$5.62	$5.94
UIL Holdings Corporation	UIL	$2.02	$2.14	$2.28	$2.42	$2.57	$2.73	$2.89	$3.07	$3.25	$3.43	$3.63	$3.83	$4.05	$4.27	$4.51	$4.76	$5.03
UniSource Energy Corporation	UNS	$2.20	$2.35	$2.52	$2.69	$2.88	$3.08	$3.28	$3.50	$3.71	$3.94	$4.17	$4.40	$4.65	$4.91	$5.18	$5.47	$5.77
Westar Energy, Inc.	WR	$2.15	$2.25	$2.36	$2.47	$2.59	$2.71	$2.84	$2.98	$3.14	$3.31	$3.49	$3.68	$3.89	$4.10	$4.33	$4.57	$4.83
Wisconsin Energy Corporation	WEC	$2.35	$2.47	$2.60	$2.74	$2.88	$3.03	$3.19	$3.36	$3.54	$3.73	$3.94	$4.16	$4.39	$4.63	$4.89	$5.17	$5.45

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Multi-Stage Growth Discounted Cash Flow Model
Combined Proxy Group
180-Day Average Stock Price

Projected Annual Dividend Payout Ratio		[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
American Electric Power Company, Inc.	AEP	64.00%	63.25%	62.50%	61.75%	61.00%	61.95%	62.89%	63.84%	64.78%	65.73%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Black Hills Corporation	BKH	66.00%	63.50%	61.00%	58.50%	56.00%	57.78%	59.56%	61.34%	63.12%	64.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Cleco Corporation	CNL	57.00%	57.00%	57.00%	57.00%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
CMS Energy Corporation	CMS	60.00%	60.50%	61.00%	61.50%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Consolidated Edison, Inc.	ED	63.00%	62.25%	61.50%	60.75%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Dominion Resources, Inc.	D	70.00%	69.50%	69.00%	68.50%	68.00%	67.78%	67.56%	67.34%	67.12%	66.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Empire District Electric Company	EDE	72.00%	71.75%	71.50%	71.25%	71.00%	70.28%	69.56%	68.84%	68.12%	67.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Great Plains Energy Inc.	GXP	56.00%	57.00%	58.00%	59.00%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Hawaiian Electric Industries, Inc.	HE	78.00%	76.50%	75.00%	73.50%	72.00%	71.11%	70.22%	69.34%	68.45%	67.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
IDACORP, Inc.	IDA	48.00%	49.00%	50.00%	51.00%	52.00%	54.45%	56.89%	59.34%	61.78%	64.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Otter Tail Corporation	OTTR	89.00%	83.25%	77.50%	71.75%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pepco Holdings, Inc.	POM	93.00%	87.00%	81.00%	75.00%	69.00%	68.61%	68.22%	67.84%	67.45%	67.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Pinnacle West Capital Corporation	PNW	62.00%	62.00%	62.00%	62.00%	62.00%	62.78%	63.56%	64.34%	65.12%	65.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
PNM Resources, Inc.	PNM	46.00%	47.25%	48.50%	49.75%	51.00%	53.61%	56.22%	58.84%	61.45%	64.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Portland General Electric Company	POR	58.00%	58.25%	58.50%	58.75%	59.00%	60.28%	61.56%	62.84%	64.12%	65.39%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
SCANA Corporation	SCG	60.00%	59.25%	58.50%	57.75%	57.00%	58.61%	60.22%	61.84%	63.45%	65.06%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Southern Company	SO	74.00%	73.00%	72.00%	71.00%	70.00%	69.45%	68.89%	68.34%	67.78%	67.23%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
UIL Holdings Corporation	UIL	80.00%	77.00%	74.00%	71.00%	68.00%	67.78%	67.56%	67.34%	67.12%	66.89%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
UniSource Energy Corporation	UNS	66.00%	64.50%	63.00%	61.50%	60.00%	61.11%	62.22%	63.34%	64.45%	65.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Westar Energy, Inc.	WR	61.00%	59.25%	57.50%	55.75%	54.00%	56.11%	58.22%	60.34%	62.45%	64.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%
Wisconsin Energy Corporation	WEC	56.00%	58.50%	61.00%	63.50%	66.00%	66.11%	66.22%	66.34%	66.45%	66.56%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%

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Multi-Stage Growth Discounted Cash Flow Model
Combined Proxy Group
180-Day Average Stock Price

Projected Annual Cash Flows		[47]	[48]	[49]	[50]	[51]	[52]	[53]	[54]	[55]	[56]	[57]	[58]	[59]	[60]	[61]	[62]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Terminal Value
American Electric Power Company, Inc.	AEP	$1.98	$2.04	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$4.00	$96.25
Black Hills Corporation	BKH	$1.40	$1.45	$1.51	$1.56	$1.61	$1.78	$1.97	$2.16	$2.37	$2.58	$2.80	$2.95	$3.12	$3.29	$3.48	$92.13
Cleco Corporation	CNL	$1.65	$1.77	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$4.55	$97.07
CMS Energy Corporation	CMS	$0.97	$1.04	$1.11	$1.18	$1.26	$1.35	$1.44	$1.54	$1.65	$1.77	$1.89	$1.99	$2.10	$2.22	$2.34	$56.36
Consolidated Edison, Inc.	ED	$2.49	$2.52	$2.56	$2.59	$2.62	$2.75	$2.90	$3.07	$3.26	$3.49	$3.75	$3.96	$4.18	$4.41	$4.66	$121.76
Dominion Resources, Inc.	D	$2.05	$2.16	$2.28	$2.40	$2.54	$2.68	$2.84	$3.00	$3.16	$3.33	$3.50	$3.70	$3.91	$4.13	$4.36	$116.14
Empire District Electric Company	EDE	$0.99	$1.02	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$1.73	$43.85
Great Plains Energy Inc.	GXP	$0.80	$0.87	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$2.14	$48.03
Hawaiian Electric Industries, Inc.	HE	$1.36	$1.39	$1.41	$1.44	$1.46	$1.50	$1.55	$1.60	$1.66	$1.73	$1.80	$1.90	$2.01	$2.12	$2.24	$52.74
IDACORP, Inc.	IDA	$1.67	$1.76	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$4.32	$101.43
Otter Tail Corporation	OTTR	$1.04	$1.08	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$2.33	$59.11
Pepco Holdings, Inc.	POM	$1.21	$1.20	$1.17	$1.15	$1.11	$1.16	$1.22	$1.28	$1.34	$1.41	$1.48	$1.56	$1.65	$1.74	$1.84	$40.80
Pinnacle West Capital Corporation	PNW	$2.28	$2.39	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$5.05	$116.81
PNM Resources, Inc.	PNM	$0.65	$0.73	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$2.44	$50.58
Portland General Electric Company	POR	$1.14	$1.20	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$2.73	$63.00
SCANA Corporation	SCG	$1.98	$2.04	$2.11	$2.18	$2.25	$2.43	$2.62	$2.83	$3.05	$3.30	$3.57	$3.77	$3.98	$4.21	$4.44	$105.20
Southern Company	SO	$2.07	$2.13	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$3.75	$91.62
UIL Holdings Corporation	UIL	$1.72	$1.75	$1.79	$1.82	$1.85	$1.96	$2.07	$2.19	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$3.18	$78.55
UniSource Energy Corporation	UNS	$1.55	$1.62	$1.69	$1.77	$1.85	$2.01	$2.17	$2.35	$2.54	$2.73	$2.93	$3.10	$3.27	$3.45	$3.65	$98.43
Westar Energy, Inc.	WR	$1.37	$1.40	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$3.05	$67.22
Wisconsin Energy Corporation	WEC	$1.38	$1.52	$1.67	$1.83	$2.00	$2.11	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.26	$3.44	$85.47

Projected Annual Data Investor Cash Flows		[63]	[64]	[65]	[66]	[67]	[68]	[69]	[70]	[71]	[72]	[73]	[74]	[75]	[76]	[77]	[78]	[79]
Company	Ticker	Initial Outflow	7/12/13	12/31/13	6/30/14	6/30/15	6/30/16	6/30/17	6/30/18	6/30/19	6/30/20	6/30/21	6/30/22	6/30/23	6/30/24	6/30/25	6/30/26	6/30/27
American Electric Power Company, Inc.	AEP	($45.68)	$0.00	$0.93	$2.02	$2.09	$2.15	$2.21	$2.34	$2.48	$2.64	$2.81	$3.00	$3.22	$3.40	$3.59	$3.79	$100.25
Black Hills Corporation	BKH	($42.13)	$0.00	$0.66	$1.46	$1.51	$1.56	$1.61	$1.78	$1.97	$2.16	$2.37	$2.58	$2.80	$2.95	$3.12	$3.29	$95.61
Cleco Corporation	CNL	($44.02)	$0.00	$0.78	$1.71	$1.89	$2.03	$2.18	$2.39	$2.62	$2.86	$3.12	$3.38	$3.66	$3.86	$4.08	$4.31	$101.62
CMS Energy Corporation	CMS	($26.29)	$0.00	$0.46	$1.00	$1.11	$1.18	$1.26	$1.35	$1.44	$1.54	$1.65	$1.77	$1.89	$1.99	$2.10	$2.22	$58.70
Consolidated Edison, Inc.	ED	($58.16)	$0.00	$1.17	$2.52	$2.56	$2.59	$2.62	$2.75	$2.90	$3.07	$3.26	$3.49	$3.75	$3.96	$4.18	$4.41	$126.41
Dominion Resources, Inc.	D	($55.34)	$0.00	$0.96	$2.11	$2.28	$2.40	$2.54	$2.68	$2.84	$3.00	$3.16	$3.33	$3.50	$3.70	$3.91	$4.13	$120.49
Empire District Electric Company	EDE	($21.57)	$0.00	$0.46	$1.00	$1.05	$1.09	$1.12	$1.15	$1.19	$1.23	$1.28	$1.34	$1.39	$1.47	$1.56	$1.64	$45.59
Great Plains Energy Inc.	GXP	($22.08)	$0.00	$0.38	$0.83	$0.94	$1.02	$1.10	$1.19	$1.29	$1.39	$1.49	$1.61	$1.72	$1.82	$1.92	$2.03	$50.17
Hawaiian Electric Industries, Inc.	HE	($26.25)	$0.00	$0.64	$1.39	$1.41	$1.44	$1.46	$1.50	$1.55	$1.60	$1.66	$1.73	$1.80	$1.90	$2.01	$2.12	$54.98
IDACORP, Inc.	IDA	($46.17)	$0.00	$0.79	$1.70	$1.86	$1.96	$2.06	$2.24	$2.44	$2.66	$2.90	$3.17	$3.48	$3.67	$3.88	$4.09	$105.75
Otter Tail Corporation	OTTR	($27.63)	$0.00	$0.49	$1.10	$1.12	$1.15	$1.18	$1.30	$1.42	$1.54	$1.66	$1.77	$1.88	$1.98	$2.09	$2.21	$61.45
Pepco Holdings, Inc.	POM	($20.34)	$0.00	$0.57	$1.25	$1.17	$1.15	$1.11	$1.16	$1.22	$1.28	$1.34	$1.41	$1.48	$1.56	$1.65	$1.74	$42.64
Pinnacle West Capital Corporation	PNW	($55.00)	$0.00	$1.07	$2.33	$2.51	$2.63	$2.77	$2.94	$3.13	$3.34	$3.56	$3.80	$4.06	$4.29	$4.53	$4.78	$121.86
PNM Resources, Inc.	PNM	($21.99)	$0.00	$0.31	$0.68	$0.81	$0.91	$1.01	$1.15	$1.29	$1.45	$1.61	$1.78	$1.96	$2.07	$2.19	$2.31	$53.02
Portland General Electric Company	POR	($29.24)	$0.00	$0.54	$1.17	$1.27	$1.34	$1.42	$1.52	$1.64	$1.76	$1.89	$2.04	$2.19	$2.32	$2.45	$2.58	$65.72
SCANA Corporation	SCG	($48.89)	$0.00	$0.93	$2.02	$2.11	$2.18	$2.25	$2.43	$2.62	$2.83	$3.05	$3.30	$3.57	$3.77	$3.98	$4.21	$109.64
Southern Company	SO	($44.77)	$0.00	$0.97	$2.11	$2.20	$2.27	$2.34	$2.43	$2.53	$2.64	$2.75	$2.88	$3.02	$3.18	$3.36	$3.55	$95.37
UIL Holdings Corporation	UIL	($37.96)	$0.00	$0.81	$1.77	$1.79	$1.82	$1.85	$1.96	$2.07	$2.19	$2.31	$2.43	$2.56	$2.70	$2.85	$3.01	$81.73
UniSource Energy Corporation	UNS	($45.68)	$0.00	$0.73	$1.61	$1.69	$1.77	$1.85	$2.01	$2.17	$2.35	$2.54	$2.73	$2.93	$3.10	$3.27	$3.45	$102.07
Westar Energy, Inc.	WR	($31.01)	$0.00	$0.65	$1.41	$1.42	$1.44	$1.46	$1.59	$1.74	$1.89	$2.06	$2.25	$2.45	$2.59	$2.74	$2.89	$70.27
Wisconsin Energy Corporation	WEC	($40.23)	$0.00	$0.65	$1.42	$1.67	$1.83	$2.00	$2.11	$2.22	$2.35	$2.48	$2.62	$2.77	$2.93	$3.09	$3.26	$88.92

DOCKET NO. 130040-EI
EXHIBIT NO. ____ (RBH-2)
WITNESS: HEVERT
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Multi-Stage Growth Discounted Cash Flow Model Notes

[1] Source: Bloomberg Professional; based on indicated historical average as of July 12, 2013
[2] Source: Zacks
[3] Source: Yahoo! Finance
[4] Source: Value Line
[5] Equals Average [2], [3], [4]
[6] Source: Bloomberg Professional, Bureau of Economic Analysis
[7] Source: Value Line
[8] Source: Value Line
[9] Equals industry average historical payout ratio (1990-present); Source: Bloomberg Professional
[10] Equals Column [1] + Column [63]
[11] Equals result of Excel Solver function; goal: Column [10] equals $0.00
[12] Equals Column [62] / Column [30]
[13] Equals Column [12] / (Column [6]) x 100)
[14] Source: Value Line
[15] Equals Column [14] x (1 + Column [5])
[16] Equals Column [15] x (1 + Column [5])
[17] Equals Column [16] x (1 + Column [5])
[18] Equals Column [17] x (1 + Column [5])
[19] Equals Column [18] x (1 + Column [5])
[20] Equals Column [19] x (1 + (Column [5] + (((Column [6] - Column [5]) / (2022 - 2017 + 1)) x (2018 - 2017))))
[21] Equals Column [20] x (1 + (Column [5] + (((Column [6] - Column [5]) / (2022 - 2017 + 1)) x (2018 - 2017))))
[22] Equals Column [21] x (1 + (Column [5] + (((Column [6] - Column [5]) / (2022 - 2017 + 1)) x (2018 - 2017))))
[23] Equals Column [22] x (1 + (Column [5] + (((Column [6] - Column [5]) / (2022 - 2017 + 1)) x (2018 - 2017))))
[24] Equals Column [23] x (1 + (Column [5] + (((Column [6] - Column [5]) / (2022 - 2017 + 1)) x (2018 - 2017))))
[25] Equals Column [24] x (1 + Column [6])
[26] Equals Column [25] x (1 + Column [6])
[27] Equals Column [26] x (1 + Column [6])
[28] Equals Column [27] x (1 + Column [6])
[29] Equals Column [28] x (1 + Column [6])
[30] Equals Column [29] x (1 + Column [6])
[31] Equals Column [7]
[32] Equals Column [31] + ((Column [35] – Column [31]) / 4)
[33] Equals Column [32] + ((Column [35] – Column [31]) / 4)
[34] Equals Column [33] + ((Column [35] – Column [31]) / 4)
[35] Equals Column [8]
[36] Equals Column [35] + ((Column [41] – Column [35]) / 6)
[37] Equals Column [36] + ((Column [41] – Column [35]) / 6)
[38] Equals Column [37] + ((Column [41] – Column [35]) / 6)
[39] Equals Column [38] + ((Column [41] – Column [35]) / 6)
[40] Equals Column [39] + ((Column [41] – Column [35]) / 6)
[41] Equals Column [9]
[42] Equals Column [9]
[43] Equals Column [9]
[44] Equals Column [9]
[45] Equals Column [9]
[46] Equals Column [9]
[47] Equals Column [15] x Column [31]
[48] Equals Column [16] x Column [32]
[49] Equals Column [17] x Column [33]
[50] Equals Column [18] x Column [34]
[51] Equals Column [19] x Column [35]
[52] Equals Column [20] x Column [36]
[53] Equals Column [21] x Column [37]
[54] Equals Column [22] x Column [38]
[55] Equals Column [23] x Column [39]
[56] Equals Column [24] x Column [40]
[57] Equals Column [25] x Column [41]
[58] Equals Column [26] x Column [42]
[59] Equals Column [27] x Column [43]
[60] Equals Column [28] x Column [44]
[61] Equals Column [29] x Column [45]
[62] Equals (Column [61] x (1 + Column [6])) / (Column [11] – Column [6])
[63] Equals negative net present value; discount rate equals Column [11], cash flows equal Column [65] through Column [80]
[64] Equals $0.00
[65] Equals Column [47] x ((7/12/13 - 12/31/13) / 365)
[66] Equals Column [47] x (1 + 0.50 x Column [5])
[67] Equals Column [49]
[68] Equals Column [50]
[69] Equals Column [51]
[70] Equals Column [52]
[71] Equals Column [53]
[72] Equals Column [54]
[73] Equals Column [55]
[74] Equals Column [56]
[75] Equals Column [57]
[76] Equals Column [58]
[77] Equals Column [59]
[78] Equals Column [60]
[79] Equals Column [61] + Column [62]

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

[1] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
13.44%	3.46%	9.98%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
AGILENT TECHNOLOGIES INC	A	15,759.78	0.10%	1.01%	6.73%	7.77%	0.0079%
ALCOA INC	AA	8,662.12	0.06%	1.48%	6.50%	8.03%	0.0045%
APPLE INC	AAPL	400,343.19	2.58%	2.66%	20.49%	23.42%	0.6052%
ABBVIE INC	ABBV	71,346.99	0.46%	3.55%	6.25%	9.91%	0.0456%
AMERISOURCEBERGEN CORP	ABC	13,482.68	0.09%	1.44%	11.60%	13.13%	0.0114%
ABBOTT LABORATORIES	ABT	55,059.10	0.36%	1.59%	11.40%	13.08%	0.0465%
ACE LTD	ACE	32,054.83	0.21%	2.13%	9.17%	11.40%	0.0236%
ACCENTURE PLC-CL A	ACN	51,886.50	0.33%	2.14%	12.75%	15.03%	0.0503%
ACTAVIS INC	ACT	16,820.45	0.11%	0.00%	11.28%	11.28%	0.0122%
ADOBE SYSTEMS INC	ADBE	24,304.43	0.16%	0.00%	11.80%	11.80%	0.0185%
ANALOG DEVICES INC	ADI	14,899.80	0.10%	2.73%	12.00%	14.90%	0.0143%
ARCHER-DANIELS-MIDLAND CO	ADM	23,929.37	0.15%	1.97%	10.00%	12.07%	0.0186%
AUTOMATIC DATA PROCESSING	ADP	35,620.18	0.23%	2.29%	9.57%	11.97%	0.0275%
AUTODESK INC	ADSK	8,095.05	0.05%	0.00%	11.60%	11.60%	0.0061%
ADT CORP/THE	ADT	9,412.17	0.06%	1.06%	9.33%	10.45%	0.0063%
AMEREN CORPORATION	AEE	8,611.10	0.06%	4.52%	2.00%	6.56%	0.0036%
AMERICAN ELECTRIC POWER	AEP	22,625.40	0.15%	4.17%	4.35%	8.60%	0.0126%
AES CORP	AES	9,406.42	0.06%	1.30%	7.96%	9.31%	0.0057%
AETNA INC	AET	24,018.65	0.16%	1.18%	10.75%	11.99%	0.0186%
AFLAC INC	AFL	27,572.60	0.18%	2.41%	11.75%	14.31%	0.0255%
ALLERGAN INC	AGN	26,827.20	0.17%	0.22%	12.92%	13.15%	0.0228%
AMERICAN INTERNATIONAL GROUP	AIG	69,004.38	0.45%	0.35%	10.75%	11.12%	0.0495%
APARTMENT INVT & MGMT CO -A	AIV	4,504.41	0.03%	3.10%	11.35%	14.62%	0.0043%
ASSURANT INC	AIZ	4,087.46	0.03%	1.77%	9.67%	11.52%	0.0030%
AKAMAI TECHNOLOGIES INC	AKAM	7,982.30	0.05%	0.00%	14.80%	14.80%	0.0076%
ALLSTATE CORP	ALL	23,952.39	0.15%	1.92%	8.88%	10.89%	0.0168%
ALTERA CORP	ALTR	11,220.91	0.07%	1.21%	12.40%	13.69%	0.0099%
ALEXION PHARMACEUTICALS INC	ALXN	22,304.61	0.14%	0.00%	23.75%	23.75%	0.0342%
APPLIED MATERIALS INC	AMAT	20,018.67	0.13%	2.21%	9.67%	11.99%	0.0155%
ADVANCED MICRO DEVICES	AMD	3,086.58	0.02%	0.00%	10.75%	10.75%	0.0021%
AMGEN INC	AMGN	78,202.50	0.50%	1.80%	8.52%	10.39%	0.0524%
AMERIPRISE FINANCIAL INC	AMP	17,452.43	0.11%	2.28%	9.50%	11.89%	0.0134%
AMERICAN TOWER CORP	AMT	30,784.60	0.20%	1.42%	19.47%	21.03%	0.0418%
AMAZON.COM INC	AMZN	140,009.89	0.90%	0.00%	33.19%	33.19%	0.3000%
AUTONATION INC	AN	5,581.03	0.04%	0.00%	22.99%	22.99%	0.0083%
ABERCROMBIE & FITCH CO-CL A	ANF	3,991.79	0.03%	1.54%	16.13%	17.80%	0.0046%
AON PLC	AON	20,717.65	0.13%	1.01%	10.00%	11.06%	0.0148%
APACHE CORP	APA	32,292.89	0.21%	0.99%	7.11%	8.14%	0.0170%
ANADARKO PETROLEUM CORP	APC	45,483.65	0.29%	0.40%	11.21%	11.64%	0.0342%
AIR PRODUCTS & CHEMICALS INC	APD	20,066.92	0.13%	2.82%	9.33%	12.28%	0.0159%
AMPHENOL CORP-CL A	APH	13,635.02	0.09%	0.49%	15.00%	15.53%	0.0137%
AIRGAS INC	ARG	7,355.04	0.05%	1.60%	12.19%	13.89%	0.0066%
ALLEGHENY TECHNOLOGIES INC	ATI	2,952.56	0.02%	2.63%	15.00%	17.83%	0.0034%
AVALONBAY COMMUNITIES INC	AVB	18,171.42	0.12%	3.05%	10.10%	13.30%	0.0156%
AVON PRODUCTS INC	AVP	9,762.19	0.06%	1.06%	18.75%	19.90%	0.0125%
AVERY DENNISON CORP	AVY	4,451.42	0.03%	2.44%	7.00%	9.52%	0.0027%
AMERICAN EXPRESS CO	AXP	86,056.37	0.56%	1.13%	11.40%	12.59%	0.0700%
AUTOZONE INC	AZO	15,604.45	0.10%	0.00%	15.98%	15.98%	0.0161%
BOEING CO/THE	BA	77,286.86	0.50%	1.87%	11.50%	13.48%	0.0672%
BANK OF AMERICA CORP	BAC	148,553.59	0.96%	0.32%	14.50%	14.84%	0.1423%
BAXTER INTERNATIONAL INC	BAX	39,291.52	0.25%	2.49%	9.85%	12.46%	0.0316%
BED BATH & BEYOND INC	BBBY	16,711.33	0.11%	0.00%	13.19%	13.19%	0.0142%
BB&T CORP	BBT	24,418.84	0.16%	2.65%	9.05%	11.82%	0.0186%
BEST BUY CO INC	BBY	10,103.64	0.07%	2.24%	9.70%	12.05%	0.0079%
CR BARD INC	BCR	8,946.36	0.06%	0.74%	10.70%	11.48%	0.0066%
BECTON DICKINSON AND CO	BDX	19,815.56	0.13%	1.91%	8.01%	10.00%	0.0128%
BEAM INC	BEAM	10,501.24	0.07%	1.38%	10.85%	12.31%	0.0083%
FRANKLIN RESOURCES INC	BEN	30,507.32	0.20%	2.90%	15.10%	18.22%	0.0359%
BROWN-FORMAN CORP-CLASS B	BF/B	15,577.50	0.10%	1.52%	12.50%	14.12%	0.0142%
BAKER HUGHES INC	BHI	21,720.24	0.14%	1.22%	13.00%	14.30%	0.0200%
BIOGEN IDEC INC	BIIB	53,727.41	0.35%	0.00%	18.84%	18.84%	0.0653%
BANK OF NEW YORK MELLON CORP	BK	34,889.04	0.23%	1.94%	12.50%	14.56%	0.0328%
BLACKROCK INC	BLK	46,837.13	0.30%	2.49%	13.84%	16.50%	0.0499%
BALL CORP	BLL	6,750.84	0.04%	1.13%	10.00%	11.19%	0.0049%
BMC SOFTWARE INC	BMC	6,602.60	0.04%	0.00%	15.00%	15.00%	0.0064%
BEMIS COMPANY	BMS	4,268.97	0.03%	2.50%	7.00%	9.59%	0.0026%
BRISTOL-MYERS SQUIBB CO	BMY	75,245.30	0.49%	3.04%	7.61%	10.77%	0.0523%
BROADCOM CORP-CL A	BRCM	19,887.93	0.13%	1.26%	13.75%	15.10%	0.0194%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
BERKSHIRE HATHAWAY INC-CL B	BRK/B	288,570.31	N/A	0.00%	NA	N/A	N/A
BOSTON SCIENTIFIC CORP	BSX	12,964.78	0.08%	0.00%	9.09%	9.09%	0.0076%
PEABODY ENERGY CORP	BTU	4,311.37	0.03%	2.15%	12.00%	14.28%	0.0040%
BORGWARNER INC	BWA	10,319.30	0.07%	0.01%	15.00%	15.01%	0.0100%
BOSTON PROPERTIES INC	BXP	16,746.39	0.11%	2.39%	6.94%	9.41%	0.0102%
CITIGROUP INC	C	154,608.97	1.00%	0.12%	10.83%	10.96%	0.1094%
CA INC	CA	13,551.51	0.09%	3.35%	7.50%	10.98%	0.0096%
CONAGRA FOODS INC	CAG	15,246.76	0.10%	2.74%	7.00%	9.84%	0.0097%
CARDINAL HEALTH INC	CAH	16,957.85	0.11%	2.18%	11.17%	13.47%	0.0147%
CAMERON INTERNATIONAL CORP	CAM	16,048.56	0.10%	0.00%	17.00%	17.00%	0.0176%
CATERPILLAR INC	CAT	57,331.71	0.37%	2.30%	10.33%	12.75%	0.0472%
CHUBB CORP	CB	22,745.00	0.15%	1.98%	9.00%	11.07%	0.0163%
CBRE GROUP INC - A	CBG	7,971.99	0.05%	0.00%	11.67%	11.67%	0.0060%
CBS CORP-CLASS B NON VOTING	CBS	32,450.22	0.21%	0.94%	10.57%	11.56%	0.0242%
COCA-COLA ENTERPRISES	CCE	10,109.44	0.07%	2.18%	8.89%	11.17%	0.0073%
CROWN CASTLE INTL CORP	CCI	22,708.44	0.15%	0.00%	23.00%	23.00%	0.0337%
CARNIVAL CORP	CCL	29,331.20	0.19%	3.26%	14.83%	18.33%	0.0347%
CELGENE CORP	CELG	56,157.20	0.36%	0.00%	23.62%	23.62%	0.0856%
CERNER CORP	CERN	17,036.69	0.11%	0.00%	18.33%	18.33%	0.0202%
CF INDUSTRIES HOLDINGS INC	CF	10,917.29	0.07%	0.87%	9.00%	9.91%	0.0070%
CAREFUSION CORP	CFN	8,475.84	0.05%	0.00%	9.93%	9.93%	0.0054%
CHESAPEAKE ENERGY CORP	CHK	14,155.63	0.09%	1.61%	21.88%	23.67%	0.0216%
C.H. ROBINSON WORLDWIDE INC	CHRW	9,285.15	0.06%	2.47%	14.50%	17.15%	0.0103%
CIGNA CORP	CI	21,693.07	0.14%	0.05%	11.03%	11.09%	0.0155%
CINCINNATI FINANCIAL CORP	CINF	8,037.77	N/A	3.33%	NA	N/A	N/A
COLGATE-PALMOLIVE CO	CL	55,162.11	0.36%	2.47%	9.14%	11.72%	0.0417%
CLIFFS NATURAL RESOURCES INC	CLF	2,581.19	0.02%	3.56%	5.00%	8.65%	0.0014%
CLOROX COMPANY	CLX	11,241.78	0.07%	2.99%	8.09%	11.20%	0.0081%
COMERICA INC	CMA	7,781.19	0.05%	1.64%	6.64%	8.33%	0.0042%
COMCAST CORP-CLASS A	CMCSA	116,682.54	0.75%	1.73%	17.61%	19.50%	0.1468%
CME GROUP INC	CME	25,823.01	0.17%	2.84%	15.00%	18.06%	0.0301%
CHIPOTLE MEXICAN GRILL INC	CMG	11,939.84	0.08%	0.00%	20.38%	20.38%	0.0157%
CUMMINS INC	CMI	21,895.86	0.14%	1.81%	10.33%	12.23%	0.0173%
CMS ENERGY CORP	CMS	7,449.79	0.05%	3.65%	6.00%	9.76%	0.0047%
CENTERPOINT ENERGY INC	CNP	10,456.14	0.07%	3.40%	5.60%	9.10%	0.0061%
CONSOL ENERGY INC	CNX	6,326.17	0.04%	1.65%	12.00%	13.75%	0.0056%
CAPITAL ONE FINANCIAL CORP	COF	39,027.91	0.25%	1.45%	8.50%	10.02%	0.0252%
CABOT OIL & GAS CORP	COG	14,898.74	0.10%	0.12%	35.00%	35.14%	0.0338%
COACH INC	COH	16,578.51	0.11%	2.05%	11.44%	13.60%	0.0146%
ROCKWELL COLLINS INC	COL	9,190.32	0.06%	1.78%	9.45%	11.31%	0.0067%
CONOCOPHILLIPS	COP	79,277.34	0.51%	4.12%	5.55%	9.78%	0.0501%
COSTCO WHOLESALE CORP	COST	50,856.25	0.33%	7.02%	12.81%	20.28%	0.0666%
COVIDIEN PLC	COV	28,002.67	0.18%	1.78%	9.43%	11.29%	0.0204%
CAMPBELL SOUP CO	CPB	14,320.11	0.09%	2.67%	6.20%	8.96%	0.0083%
SALESFORCE.COM INC	CRM	25,030.94	0.16%	0.00%	29.48%	29.48%	0.0476%
COMPUTER SCIENCES CORP	CSC	7,179.43	0.05%	1.67%	8.00%	9.74%	0.0045%
CISCO SYSTEMS INC	CSCO	138,632.08	0.89%	2.39%	10.57%	13.09%	0.1171%
CSX CORP	CSX	24,894.96	0.16%	2.43%	12.10%	14.68%	0.0236%
CINTAS CORP	CTAS	5,880.99	0.04%	1.34%	10.60%	12.01%	0.0046%
CENTURYLINK INC	CTL	22,071.83	0.14%	5.96%	3.13%	9.18%	0.0131%
COGNIZANT TECH SOLUTIONS-A	CTSH	21,544.40	0.14%	0.00%	18.57%	18.57%	0.0258%
CITRIX SYSTEMS INC	CTXS	12,614.01	0.08%	0.00%	14.04%	14.04%	0.0114%
CABLEVISION SYSTEMS-NY GRP-A	CVC	4,980.84	0.03%	3.24%	17.63%	21.16%	0.0068%
CVS CAREMARK CORP	CVS	74,626.73	0.48%	1.49%	13.50%	15.09%	0.0727%
CHEVRON CORP	CVX	240,549.58	1.55%	3.09%	5.11%	8.28%	0.1286%
DOMINION RESOURCES INC/VA	D	33,967.38	0.22%	3.83%	5.69%	9.63%	0.0211%
DU PONT (E.I.) DE NEMOURS	DD	50,082.55	0.32%	3.24%	7.84%	11.21%	0.0362%
DEERE & CO	DE	32,572.45	0.21%	2.31%	9.25%	11.67%	0.0245%
DELL INC	DELL	23,390.90	0.15%	2.45%	5.50%	8.02%	0.0121%
DISCOVER FINANCIAL SERVICES	DFS	24,957.72	0.16%	1.47%	10.50%	12.05%	0.0194%
DOLLAR GENERAL CORP	DG	17,604.04	0.11%	0.00%	15.85%	15.85%	0.0180%
QUEST DIAGNOSTICS INC	DGX	9,375.88	0.06%	1.87%	10.88%	12.84%	0.0078%
DR HORTON INC	DHI	7,313.39	0.05%	0.68%	5.23%	5.93%	0.0028%
DANAHER CORP	DHR	47,235.70	0.30%	0.18%	13.00%	13.19%	0.0402%
WALT DISNEY CO/THE	DIS	120,627.07	0.78%	1.09%	11.63%	12.79%	0.0996%
DISCOVERY COMMUNICATIONS-A	DISCA	30,534.19	0.20%	0.00%	18.81%	18.81%	0.0371%
DELPHI AUTOMOTIVE PLC	DLPH	17,173.62	0.11%	0.93%	12.50%	13.48%	0.0149%
DOLLAR TREE INC	DLTR	12,080.31	0.08%	0.00%	15.80%	15.80%	0.0123%
DUN & BRADSTREET CORP	DNB	4,297.83	N/A	0.00%	NA	N/A	N/A
DENBURY RESOURCES INC	DNR	6,623.67	N/A	0.00%	NA	N/A	N/A
DIAMOND OFFSHORE DRILLING	DO	10,025.85	0.06%	4.86%	18.00%	23.29%	0.0151%
DOVER CORP	DOV	13,859.37	0.09%	1.79%	15.00%	16.93%	0.0151%
DOW CHEMICAL CO/THE	DOW	41,271.18	0.27%	3.80%	8.76%	12.73%	0.0339%
DR PEPPER SNAPPLE GROUP INC	DPS	9,684.40	0.06%	3.18%	7.18%	10.47%	0.0065%
DARDEN RESTAURANTS INC	DRI	6,546.43	0.04%	4.45%	9.34%	14.00%	0.0059%
DTE ENERGY COMPANY	DTE	12,000.87	0.08%	3.75%	4.75%	8.59%	0.0067%
DIRECTV	DTV	36,255.64	0.23%	0.00%	15.95%	15.95%	0.0373%
DUKE ENERGY CORP	DUK	49,525.90	0.32%	4.42%	4.48%	9.00%	0.0288%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
DAVITA HEALTHCARE PARTNERS I	DVA	12,826.13	0.08%	0.00%	12.40%	12.40%	0.0103%
DEVON ENERGY CORPORATION	DVN	22,593.90	0.15%	1.52%	5.22%	6.78%	0.0099%
ELECTRONIC ARTS INC	EA	7,360.07	0.05%	0.00%	16.93%	16.93%	0.0080%
EBAY INC	EBAY	74,025.91	0.48%	0.00%	14.59%	14.59%	0.0697%
ECOLAB INC	ECL	26,726.92	0.17%	1.00%	13.64%	14.71%	0.0254%
CONSOLIDATED EDISON INC	ED	17,339.35	0.11%	4.15%	3.20%	7.41%	0.0083%
EQUIFAX INC	EFX	7,368.05	0.05%	1.44%	11.33%	12.86%	0.0061%
EDISON INTERNATIONAL	EIX	15,792.07	0.10%	2.81%	4.84%	7.71%	0.0079%
ESTEE LAUDER COMPANIES-CL A	EL	26,553.25	0.17%	1.50%	14.18%	15.78%	0.0270%
EMC CORP/MA	EMC	52,394.95	0.34%	0.50%	13.29%	13.82%	0.0467%
EASTMAN CHEMICAL CO	EMN	11,452.33	0.07%	1.63%	7.67%	9.35%	0.0069%
EMERSON ELECTRIC CO	EMR	41,133.32	0.27%	2.86%	9.71%	12.72%	0.0338%
EOG RESOURCES INC	EOG	39,347.19	0.25%	0.50%	10.97%	11.50%	0.0292%
EQUITY RESIDENTIAL	EQR	21,116.00	0.14%	3.18%	7.37%	10.67%	0.0145%
EQT CORP	EQT	12,362.76	0.08%	0.25%	30.00%	30.29%	0.0242%
EXPRESS SCRIPTS HOLDING CO	ESRX	53,384.64	0.34%	0.00%	16.77%	16.77%	0.0578%
ENSCO PLC-CL A	ESV	14,020.74	0.09%	3.29%	16.00%	19.55%	0.0177%
E*TRADE FINANCIAL CORP	ETFC	3,849.32	0.02%	0.00%	28.83%	28.83%	0.0072%
EATON CORP PLC	ETN	32,299.78	0.21%	2.45%	11.12%	13.71%	0.0286%
ENTERGY CORP	ETR	12,631.53	0.08%	4.68%	-0.49%	4.19%	0.0034%
EDWARDS LIFESCIENCES CORP	EW	7,664.45	0.05%	0.00%	17.80%	17.80%	0.0088%
EXELON CORP	EXC	26,565.56	0.17%	4.63%	-0.40%	4.22%	0.0072%
EXPEDITORS INTL WASH INC	EXPD	8,264.38	0.05%	1.50%	11.13%	12.70%	0.0068%
EXPEDIA INC	EXPE	8,614.94	0.06%	0.77%	14.05%	14.87%	0.0083%
FORD MOTOR CO	F	67,262.94	0.43%	2.34%	6.18%	8.59%	0.0373%
FASTENAL CO	FAST	13,982.86	0.09%	1.37%	17.97%	19.46%	0.0176%
FREEPORT-MCMORAN COPPER	FCX	29,012.48	0.19%	4.46%	7.00%	11.61%	0.0217%
FAMILY DOLLAR STORES	FDO	7,865.99	0.05%	1.40%	11.55%	13.04%	0.0066%
FEDEX CORP	FDX	32,483.91	0.21%	0.59%	12.45%	13.08%	0.0274%
FIRSTENERGY CORP	FE	15,662.21	0.10%	5.87%	4.50%	10.51%	0.0106%
F5 NETWORKS INC	FFIV	6,287.39	0.04%	0.00%	14.38%	14.38%	0.0058%
FIDELITY NATIONAL INFORMATIO	FIS	13,182.08	0.09%	1.95%	12.40%	14.47%	0.0123%
FISERV INC	FISV	12,125.79	0.08%	0.00%	11.83%	11.83%	0.0093%
FIFTH THIRD BANCORP	FITB	17,284.20	0.11%	2.46%	12.98%	15.60%	0.0174%
FLIR SYSTEMS INC	FLIR	4,141.59	0.03%	1.23%	12.50%	13.81%	0.0037%
FLUOR CORP	FLR	10,015.05	0.06%	0.99%	12.15%	13.20%	0.0085%
FLOWSERVE CORP	FLS	7,936.95	0.05%	0.88%	12.33%	13.27%	0.0068%
FMC CORP	FMC	8,456.40	0.05%	0.90%	11.34%	12.30%	0.0067%
FOSSIL GROUP INC	FOSL	6,425.22	0.04%	0.00%	16.37%	16.37%	0.0068%
TWENTY-FIRST CENTURY FOX INC	FOXA	69,955.91	0.45%	0.59%	14.84%	15.47%	0.0698%
FOREST LABORATORIES INC	FRX	11,712.14	0.08%	0.00%	34.64%	34.64%	0.0262%
FIRST SOLAR INC	FSLR	4,710.77	0.03%	0.00%	0.00%	0.00%	0.0000%
FMC TECHNOLOGIES INC	FTI	13,856.89	0.09%	0.00%	15.33%	15.33%	0.0137%
FRONTIER COMMUNICATIONS CORP	FTR	4,020.94	0.03%	9.93%	4.03%	14.16%	0.0037%
AGL RESOURCES INC	GAS	5,285.04	0.03%	4.17%	2.94%	7.17%	0.0024%
GANNETT CO	GCI	6,102.10	0.04%	3.25%	4.50%	7.83%	0.0031%
GENERAL DYNAMICS CORP	GD	29,173.22	0.19%	2.61%	5.28%	7.96%	0.0150%
GENERAL ELECTRIC CO	GE	245,681.27	1.59%	3.24%	9.75%	13.15%	0.2086%
GILEAD SCIENCES INC	GILD	87,540.17	0.57%	0.00%	25.39%	25.39%	0.1434%
GENERAL MILLS INC	GIS	32,741.56	0.21%	2.95%	7.83%	10.90%	0.0230%
CORNING INC	GLW	22,170.59	0.14%	2.56%	11.50%	14.21%	0.0203%
GENERAL MOTORS CO	GM	50,038.58	0.32%	0.00%	12.50%	12.50%	0.0404%
GAMESTOP CORP-CLASS A	GME	5,078.13	0.03%	1.86%	13.88%	15.87%	0.0052%
GENWORTH FINANCIAL INC-CL A	GNW	6,277.17	0.04%	0.00%	5.00%	5.00%	0.0020%
GOOGLE INC-CL A	GOOG	306,220.09	1.98%	0.00%	15.32%	15.32%	0.3028%
GENUINE PARTS CO	GPC	13,176.79	0.09%	2.52%	7.89%	10.50%	0.0089%
GAP INC/THE	GPS	21,093.26	0.14%	1.15%	12.76%	13.98%	0.0190%
GARMIN LTD	GRMN	7,104.36	0.05%	4.96%	6.54%	11.66%	0.0053%
GOLDMAN SACHS GROUP INC	GS	76,264.09	0.49%	1.26%	10.05%	11.37%	0.0560%
GOODYEAR TIRE & RUBBER CO	GT	4,078.47	0.03%	0.04%	24.02%	24.06%	0.0063%
WW GRAINGER INC	GWW	18,446.56	0.12%	1.30%	15.00%	16.39%	0.0195%
HALLIBURTON CO	HAL	41,559.50	0.27%	1.10%	14.67%	15.85%	0.0425%
HARMAN INTERNATIONAL	HAR	3,753.44	0.02%	1.00%	17.50%	18.59%	0.0045%
HASBRO INC	HAS	6,163.37	0.04%	3.15%	8.00%	11.27%	0.0045%
HUNTINGTON BANCSHARES INC	HBAN	6,986.85	0.05%	2.28%	5.25%	7.59%	0.0034%
HUDSON CITY BANCORP INC	HCBK	5,141.52	N/A	1.97%	NA	N/A	N/A
HEALTH CARE REIT INC	HCN	19,088.28	0.12%	4.55%	5.68%	10.36%	0.0128%
HCP INC	HCP	21,079.07	0.14%	4.53%	4.53%	9.17%	0.0125%
HOME DEPOT INC	HD	117,652.54	0.76%	1.95%	16.38%	18.49%	0.1404%
HESS CORP	HES	24,432.51	0.16%	1.02%	5.36%	6.41%	0.0101%
HARTFORD FINANCIAL SVCS GRP	HIG	14,684.17	0.09%	1.31%	9.00%	10.37%	0.0098%
HARLEY-DAVIDSON INC	HOG	12,542.81	0.08%	1.50%	12.33%	13.93%	0.0113%
HONEYWELL INTERNATIONAL INC	HON	64,807.39	0.42%	1.99%	11.16%	13.26%	0.0555%
STARWOOD HOTELS & RESORTS	HOT	12,987.08	0.08%	1.96%	13.19%	15.27%	0.0128%
HELMERICH & PAYNE	HP	6,968.01	0.04%	0.87%	9.00%	9.91%	0.0045%
HEWLETT-PACKARD CO	HPQ	50,508.77	0.33%	2.02%	3.00%	5.05%	0.0165%
H&R BLOCK INC	HRB	8,352.83	0.05%	2.71%	13.50%	16.39%	0.0088%
HORMEL FOODS CORP	HRL	10,853.20	0.07%	1.61%	8.50%	10.18%	0.0071%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
HARRIS CORP	HRS	5,672.04	0.04%	2.87%	2.00%	4.89%	0.0018%
HOSPIRA INC	HSP	6,566.75	0.04%	0.00%	10.11%	10.11%	0.0043%
HOST HOTELS & RESORTS INC	HST	13,397.60	0.09%	2.32%	12.50%	14.97%	0.0129%
HERSHEY CO/THE	HSY	20,501.47	0.13%	1.82%	8.50%	10.40%	0.0138%
HUMANA INC	HUM	13,471.13	0.09%	1.25%	10.21%	11.53%	0.0100%
INTL BUSINESS MACHINES CORP	IBM	212,966.14	1.37%	1.81%	9.40%	11.30%	0.1553%
INTERCONTINENTALEXCHANGE INC	ICE	13,147.46	0.08%	0.00%	18.00%	18.00%	0.0153%
INTL FLAVORS & FRAGRANCES	IFF	6,532.49	0.04%	1.73%	7.33%	9.13%	0.0038%
INTL GAME TECHNOLOGY	IGT	4,598.66	0.03%	1.55%	14.25%	15.91%	0.0047%
INTEL CORP	INTC	118,806.90	0.77%	3.79%	9.16%	13.13%	0.1006%
INTUIT INC	INTU	19,217.00	0.12%	0.91%	13.00%	13.97%	0.0173%
INTERNATIONAL PAPER CO	IP	21,410.53	0.14%	2.55%	5.50%	8.12%	0.0112%
INTERPUBLIC GROUP OF COS INC	IPG	6,730.13	0.04%	1.90%	14.50%	16.53%	0.0072%
INGERSOLL-RAND PLC	IR	17,661.54	0.11%	1.44%	10.00%	11.51%	0.0131%
IRON MOUNTAIN INC	IRM	5,381.78	0.03%	3.83%	13.00%	17.07%	0.0059%
INTUITIVE SURGICAL INC	ISRG	17,230.69	0.11%	0.00%	15.50%	15.50%	0.0172%
ILLINOIS TOOL WORKS	ITW	32,446.90	0.21%	1.96%	9.28%	11.33%	0.0237%
INVESCO LTD	IVZ	14,117.54	0.09%	2.71%	13.75%	16.64%	0.0152%
JABIL CIRCUIT INC	JBL	4,448.33	0.03%	1.46%	12.00%	13.55%	0.0039%
JOHNSON CONTROLS INC	JCI	25,283.18	0.16%	2.15%	12.78%	15.07%	0.0246%
J.C. PENNEY CO INC	JCP	3,870.65	0.02%	0.00%	11.70%	11.70%	0.0029%
JDS UNIPHASE CORP	JDSU	3,557.74	0.02%	0.00%	15.00%	15.00%	0.0034%
JACOBS ENGINEERING GROUP INC	JEC	7,554.87	0.05%	0.00%	13.80%	13.80%	0.0067%
JOHNSON & JOHNSON	JNJ	252,771.73	1.63%	2.85%	6.46%	9.39%	0.1533%
JUNIPER NETWORKS INC	JNPR	10,302.26	0.07%	0.00%	14.20%	14.20%	0.0094%
JOY GLOBAL INC	JOY	5,478.92	0.04%	1.36%	8.10%	9.51%	0.0034%
JPMORGAN CHASE & CO	JPM	207,768.80	1.34%	2.59%	9.97%	12.69%	0.1702%
NORDSTROM INC	JWN	12,182.28	0.08%	1.76%	11.90%	13.77%	0.0108%
KELLOGG CO	K	24,456.98	0.16%	2.69%	7.81%	10.61%	0.0167%
KEYCORP	KEY	10,852.82	0.07%	1.87%	5.00%	6.91%	0.0048%
KIMCO REALTY CORP	KIM	9,131.57	0.06%	3.78%	5.10%	8.98%	0.0053%
KLA-TENCOR CORPORATION	KLAC	10,017.84	0.06%	2.63%	10.00%	12.76%	0.0082%
KIMBERLY-CLARK CORP	KMB	38,423.84	0.25%	3.22%	7.61%	10.95%	0.0271%
KINDER MORGAN INC	KMI	41,499.26	0.27%	3.95%	2.50%	6.50%	0.0174%
CARMAX INC	KMX	10,758.98	0.07%	0.00%	13.03%	13.03%	0.0091%
COCA-COLA CO/THE	KO	182,737.58	1.18%	2.73%	8.02%	10.86%	0.1281%
KROGER CO	KR	19,501.49	0.13%	1.59%	8.82%	10.48%	0.0132%
KRAFT FOODS GROUP INC	KRFT	33,700.54	0.22%	3.55%	6.60%	10.27%	0.0223%
KOHLS CORP	KSS	11,846.45	0.08%	2.45%	9.14%	11.70%	0.0089%
KANSAS CITY SOUTHERN	KSU	12,539.81	0.08%	0.75%	17.00%	17.82%	0.0144%
LOEWS CORP	L	17,767.94	N/A	0.55%	NA	N/A	N/A
LEGGETT & PLATT INC	LEG	4,611.20	0.03%	3.47%	15.00%	18.73%	0.0056%
LENNAR CORP-A	LEN	6,900.98	0.04%	0.43%	8.00%	8.45%	0.0038%
LABORATORY CRP OF AMER HLDGS	LH	8,983.43	0.06%	0.00%	11.25%	11.25%	0.0065%
LIFE TECHNOLOGIES CORP	LIFE	12,836.96	0.08%	0.00%	9.53%	9.53%	0.0079%
L-3 COMMUNICATIONS HOLDINGS	LLL	8,119.42	0.05%	2.42%	3.07%	5.52%	0.0029%
LINEAR TECHNOLOGY CORP	LLTC	9,306.86	0.06%	2.56%	10.51%	13.20%	0.0079%
ELI LILLY & CO	LLY	57,961.59	0.37%	3.81%	1.36%	5.19%	0.0194%
LEGG MASON INC	LM	4,088.80	0.03%	1.57%	14.95%	16.64%	0.0044%
LOCKHEED MARTIN CORP	LMT	36,055.21	0.23%	4.18%	6.60%	10.92%	0.0254%
LINCOLN NATIONAL CORP	LNC	10,620.35	0.07%	1.20%	9.00%	10.26%	0.0070%
LORILLARD INC	LO	17,440.92	0.11%	4.77%	12.23%	17.28%	0.0195%
LOWE'S COS INC	LOW	47,004.02	0.30%	1.57%	16.26%	17.95%	0.0545%
LAM RESEARCH CORP	LRCX	8,205.83	0.05%	0.00%	11.00%	11.00%	0.0058%
LSI CORP	LSI	4,143.68	0.03%	0.00%	15.33%	15.33%	0.0041%
L BRANDS INC	LTD	14,995.86	0.10%	2.58%	12.13%	14.86%	0.0144%
LEUCADIA NATIONAL CORP	LUK	9,751.05	N/A	0.00%	NA	N/A	N/A
SOUTHWEST AIRLINES CO	LUV	9,722.12	0.06%	0.41%	18.72%	19.16%	0.0120%
LYONDELLBASELL INDU-CL A	LYB	40,271.30	0.26%	2.56%	10.45%	13.14%	0.0342%
MACY'S INC	M	18,964.01	0.12%	1.87%	9.70%	11.66%	0.0143%
MASTERCARD INC-CLASS A	MA	72,802.34	0.47%	0.29%	17.91%	18.23%	0.0857%
MACERICH CO/THE	MAC	8,769.66	0.06%	3.69%	5.23%	9.02%	0.0051%
MARRIOTT INTERNATIONAL -CL A	MAR	12,816.52	0.08%	1.29%	15.14%	16.53%	0.0137%
MASCO CORP	MAS	7,404.99	0.05%	1.46%	8.00%	9.52%	0.0045%
MATTEL INC	MAT	16,261.34	0.10%	3.06%	9.50%	12.70%	0.0133%
MCDONALD'S CORP	MCD	101,838.92	0.66%	3.12%	9.59%	12.86%	0.0845%
MICROCHIP TECHNOLOGY INC	MCHP	7,781.53	0.05%	3.61%	12.00%	15.83%	0.0080%
MCKESSON CORP	MCK	27,107.69	0.17%	0.71%	13.00%	13.75%	0.0241%
MOODY'S CORP	MCO	13,648.54	N/A	1.31%	NA	N/A	N/A
MONDELEZ INTERNATIONAL INC-A	MDLZ	54,175.98	0.35%	1.74%	10.63%	12.46%	0.0436%
MEDTRONIC INC	MDT	53,836.13	0.35%	2.10%	6.67%	8.84%	0.0307%
METLIFE INC	MET	53,743.25	0.35%	2.05%	5.25%	7.35%	0.0255%
MCGRAW HILL FINANCIAL INC	MHFI	15,744.30	0.10%	1.95%	15.60%	17.70%	0.0180%
MEAD JOHNSON NUTRITION CO	MJN	15,037.82	0.10%	1.81%	10.80%	12.71%	0.0123%
MCCORMICK & CO-NON VTG SHRS	MKC	9,452.06	0.06%	1.90%	8.25%	10.23%	0.0062%
MARSH & MCLENNAN COS	MMC	22,961.08	0.15%	2.26%	12.00%	14.40%	0.0213%
3M CO	MMM	79,469.01	0.51%	2.21%	11.88%	14.21%	0.0729%
MONSTER BEVERAGE CORP	MNST	9,934.59	0.06%	0.00%	14.00%	14.00%	0.0090%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
ALTRIA GROUP INC	MO	74,159.80	0.48%	4.99%	7.59%	12.77%	0.0611%
MOLEX INC	MOLX	4,945.54	0.03%	2.96%	12.50%	15.64%	0.0050%
MONSANTO CO	MON	54,883.61	0.35%	1.46%	15.05%	16.62%	0.0589%
MOSAIC CO/THE	MOS	23,881.24	0.15%	1.78%	6.76%	8.61%	0.0133%
MARATHON PETROLEUM CORP	MPC	23,787.43	0.15%	2.11%	11.00%	13.22%	0.0203%
MERCK & CO. INC.	MRK	146,571.97	0.95%	3.53%	3.99%	7.59%	0.0718%
MARATHON OIL CORP	MRO	26,112.82	0.17%	1.88%	12.67%	14.66%	0.0247%
MORGAN STANLEY	MS	51,217.80	0.33%	0.81%	6.78%	7.61%	0.0252%
MICROSOFT CORP	MSFT	298,385.03	1.93%	2.52%	8.50%	11.13%	0.2143%
MOTOROLA SOLUTIONS INC	MSI	16,174.50	0.10%	1.89%	12.50%	14.51%	0.0151%
M & T BANK CORP	MTB	15,194.67	0.10%	2.39%	12.50%	15.03%	0.0147%
MICRON TECHNOLOGY INC	MU	13,178.25	0.09%	0.00%	12.27%	12.27%	0.0104%
MURPHY OIL CORP	MUR	12,333.08	0.08%	2.51%	13.00%	15.67%	0.0125%
MEADWESTVACO CORP	MWV	6,377.48	0.04%	2.79%	10.00%	12.93%	0.0053%
MYLAN INC	MYL	12,229.16	0.08%	0.00%	8.87%	8.87%	0.0070%
NOBLE ENERGY INC	NBL	22,990.30	0.15%	0.89%	7.00%	7.92%	0.0118%
NABORS INDUSTRIES LTD	NBR	4,360.36	0.03%	0.57%	10.00%	10.60%	0.0030%
NASDAQ OMX GROUP/THE	NDAQ	5,686.75	0.04%	1.37%	12.63%	14.09%	0.0052%
NOBLE CORP	NE	10,194.28	0.07%	1.88%	13.67%	15.68%	0.0103%
NEXTERA ENERGY INC	NEE	35,673.85	0.23%	3.12%	5.94%	9.16%	0.0211%
NEWMONT MINING CORP	NEM	13,685.39	0.09%	4.49%	2.00%	6.53%	0.0058%
NETFLIX INC	NFLX	14,445.85	0.09%	0.00%	20.00%	20.00%	0.0186%
NEWFIELD EXPLORATION CO	NFX	3,487.74	0.02%	0.00%	11.50%	11.50%	0.0026%
NISOURCE INC	NI	9,451.60	0.06%	3.24%	4.00%	7.30%	0.0045%
NIKE INC -CL B	NKE	56,896.44	0.37%	1.42%	11.83%	13.34%	0.0490%
NIELSEN HOLDINGS NV	NLSN	12,953.49	0.08%	1.33%	16.47%	17.91%	0.0150%
NORTHROP GRUMMAN CORP	NOC	20,699.57	0.13%	2.64%	7.50%	10.24%	0.0137%
NATIONAL OILWELL VARCO INC	NOV	31,174.44	0.20%	0.88%	11.33%	12.26%	0.0247%
NRG ENERGY INC	NRG	9,236.04	N/A	1.63%	NA	N/A	N/A
NORFOLK SOUTHERN CORP	NSC	23,694.64	0.15%	2.72%	11.60%	14.48%	0.0221%
NETAPP INC	NTAP	14,191.65	0.09%	1.67%	13.17%	14.95%	0.0137%
NORTHERN TRUST CORP	NTRS	14,715.65	0.09%	1.98%	14.52%	16.63%	0.0158%
NORTHEAST UTILITIES	NU	13,616.81	0.09%	3.39%	7.60%	11.12%	0.0098%
NUCOR CORP	NUE	14,262.12	0.09%	3.27%	7.33%	10.73%	0.0099%
NVIDIA CORP	NVDA	8,460.70	0.05%	2.07%	10.40%	12.58%	0.0069%
NEWELL RUBBERMAID INC	NWL	7,801.04	0.05%	2.25%	8.83%	11.18%	0.0056%
NEWS CORP - CLASS A	NWSA	8,649.04	0.06%	0.78%	10.00%	10.82%	0.0060%
NYSE EURONEXT	NYX	10,150.11	0.07%	2.88%	10.00%	13.02%	0.0085%
OWENS-ILLINOIS INC	OI	4,824.63	0.03%	0.00%	8.67%	8.67%	0.0027%
ONEOK INC	OKE	8,897.64	0.06%	3.40%	9.00%	12.55%	0.0072%
OMNICOM GROUP	OMC	17,154.43	0.11%	2.41%	7.70%	10.20%	0.0113%
ORACLE CORP	ORCL	144,712.72	0.93%	1.36%	10.89%	12.32%	0.1151%
O'REILLY AUTOMOTIVE INC	ORLY	12,919.41	0.08%	0.00%	19.20%	19.20%	0.0160%
OCCIDENTAL PETROLEUM CORP	OXY	72,685.18	0.47%	2.73%	7.09%	9.91%	0.0465%
PAYCHEX INC	PAYX	14,361.30	0.09%	3.38%	9.57%	13.11%	0.0122%
PEOPLE'S UNITED FINANCIAL	PBCT	5,027.16	0.03%	4.27%	6.50%	10.91%	0.0035%
PITNEY BOWES INC	PBI	2,812.57	0.02%	6.70%	7.00%	13.93%	0.0025%
PACCAR INC	PCAR	20,038.25	0.13%	2.32%	10.25%	12.69%	0.0164%
P G & E CORP	PCG	20,136.58	0.13%	4.00%	5.88%	10.00%	0.0130%
PLUM CREEK TIMBER CO	PCL	7,894.52	0.05%	3.49%	5.00%	8.58%	0.0044%
PRICELINE COM INC	PCLN	47,473.64	0.31%	0.00%	18.67%	18.67%	0.0572%
PRECISION CASTPARTS CORP	PCP	34,283.54	0.22%	0.05%	11.87%	11.92%	0.0264%
PATTERSON COS INC	PDCO	4,169.28	0.03%	1.63%	9.75%	11.46%	0.0031%
PUBLIC SERVICE ENTERPRISE GP	PEG	16,777.92	0.11%	4.35%	0.76%	5.13%	0.0055%
PEPSICO INC	PEP	130,393.82	0.84%	2.66%	8.22%	10.99%	0.0925%
PETSMART INC	PETM	7,438.76	0.05%	0.94%	15.45%	16.47%	0.0079%
PFIZER INC	PFE	204,355.77	1.32%	3.31%	4.06%	7.43%	0.0980%
PRINCIPAL FINANCIAL GROUP	PFG	11,414.05	0.07%	2.41%	11.50%	14.04%	0.0103%
PROCTER & GAMBLE CO/THE	PG	223,510.08	1.44%	2.82%	8.64%	11.58%	0.1671%
PROGRESSIVE CORP	PGR	15,592.39	0.10%	1.59%	8.25%	9.90%	0.0100%
PARKER HANNIFIN CORP	PH	14,799.76	0.10%	1.70%	6.20%	7.95%	0.0076%
PULTEGROUP INC	PHM	7,835.25	0.05%	0.00%	52.20%	52.20%	0.0264%
PERKINELMER INC	PKI	3,784.61	0.02%	0.83%	9.95%	10.83%	0.0026%
PROLOGIS INC	PLD	19,591.96	0.13%	2.90%	7.01%	10.00%	0.0127%
PALL CORP	PLL	7,879.29	0.05%	1.35%	11.55%	12.98%	0.0066%
PHILIP MORRIS INTERNATIONAL	PM	146,704.98	0.95%	3.97%	9.97%	14.14%	0.1339%
PNC FINANCIAL SERVICES GROUP	PNC	39,659.13	0.26%	2.29%	4.40%	6.74%	0.0173%
PENTAIR LTD-REGISTERED	PNR	12,469.73	0.08%	1.48%	12.50%	14.07%	0.0113%
PINNACLE WEST CAPITAL	PNW	6,360.46	0.04%	3.82%	4.69%	8.61%	0.0035%
PEPCO HOLDINGS INC	POM	5,031.30	0.03%	5.34%	5.17%	10.64%	0.0035%
PPG INDUSTRIES INC	PPG	22,499.62	0.15%	1.53%	8.76%	10.36%	0.0150%
PPL CORPORATION	PPL	18,036.74	0.12%	4.83%	-0.57%	4.25%	0.0049%
PERRIGO CO	PRGO	12,019.85	0.08%	0.28%	11.61%	11.92%	0.0092%
PRUDENTIAL FINANCIAL INC	PRU	36,296.74	0.23%	2.14%	10.67%	12.92%	0.0303%
PUBLIC STORAGE	PSA	28,671.95	0.19%	3.14%	5.67%	8.90%	0.0165%
PHILLIPS 66	PSX	36,645.36	0.24%	2.20%	10.00%	12.31%	0.0291%
PVH CORP	PVH	10,632.62	0.07%	0.12%	13.28%	13.40%	0.0092%
QUANTA SERVICES INC	PWR	5,821.90	0.04%	0.00%	20.63%	20.63%	0.0078%

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PRAXAIR INC	PX	34,629.41	0.22%	2.05%	10.64%	12.80%	0.0286%
PIONEER NATURAL RESOURCES CO	PXD	20,955.18	0.14%	0.06%	17.92%	17.99%	0.0243%
QUALCOMM INC	QCOM	107,160.35	0.69%	1.74%	14.19%	16.05%	0.1110%
QEP RESOURCES INC	QEP	5,309.82	0.03%	0.27%	15.00%	15.29%	0.0052%
RYDER SYSTEM INC	R	3,157.91	0.02%	2.08%	9.50%	11.68%	0.0024%
REYNOLDS AMERICAN INC	RAI	28,093.69	0.18%	4.87%	8.01%	13.08%	0.0237%
ROWAN COMPANIES PLC-A	RDC	4,366.85	0.03%	0.00%	13.00%	13.00%	0.0037%
REGENERON PHARMACEUTICALS	REGN	26,072.68	0.17%	0.00%	22.71%	22.71%	0.0382%
REGIONS FINANCIAL CORP	RF	14,133.79	0.09%	1.02%	6.00%	7.05%	0.0064%
ROBERT HALF INTL INC	RHI	4,817.06	0.03%	1.83%	13.33%	15.29%	0.0048%
RED HAT INC	RHT	9,514.44	0.06%	0.00%	17.00%	17.00%	0.0104%
RALPH LAUREN CORP	RL	16,719.92	0.11%	0.97%	12.80%	13.84%	0.0149%
ROCKWELL AUTOMATION INC	ROK	12,709.56	0.08%	2.12%	12.00%	14.25%	0.0117%
ROPER INDUSTRIES INC	ROP	12,912.98	0.08%	0.56%	15.00%	15.60%	0.0130%
ROSS STORES INC	ROST	14,662.33	0.09%	0.98%	11.56%	12.60%	0.0119%
RANGE RESOURCES CORP	RRC	12,605.51	0.08%	0.21%	27.00%	27.24%	0.0222%
REPUBLIC SERVICES INC	RSG	12,760.91	0.08%	2.66%	2.30%	4.99%	0.0041%
RAYTHEON COMPANY	RTN	22,550.94	0.15%	3.11%	9.00%	12.25%	0.0178%
SAIC INC	SAI	4,829.51	0.03%	8.16%	6.83%	15.27%	0.0048%
STARBUCKS CORP	SBUX	52,241.20	0.34%	1.23%	18.00%	19.34%	0.0652%
SCANA CORP	SCG	7,120.00	0.05%	3.97%	5.00%	9.07%	0.0042%
SCHWAB (CHARLES) CORP	SCHW	27,762.75	0.18%	1.13%	20.45%	21.70%	0.0389%
SPECTRA ENERGY CORP	SE	23,830.09	0.15%	3.50%	5.50%	9.10%	0.0140%
SEALED AIR CORP	SEE	5,387.53	0.03%	1.82%	5.50%	7.37%	0.0026%
SHERWIN-WILLIAMS CO/THE	SHW	19,328.90	0.12%	1.01%	12.50%	13.57%	0.0169%
SIGMA-ALDRICH	SIAL	10,150.22	0.07%	1.03%	7.24%	8.31%	0.0054%
JM SMUCKER CO/THE	SJM	11,235.03	0.07%	2.11%	8.18%	10.37%	0.0075%
SCHLUMBERGER LTD	SLB	102,154.94	0.66%	1.59%	17.00%	18.73%	0.1235%
SLM CORP	SLM	10,394.52	N/A	2.56%	NA	N/A	N/A
SNAP-ON INC	SNA	5,434.53	0.04%	0.00%	10.00%	10.00%	0.0035%
SANDISK CORP	SNDK	14,821.15	0.10%	0.00%	18.50%	18.50%	0.0177%
SCRIPPS NETWORKS INTER-CL A	SNI	10,655.82	0.07%	0.76%	12.58%	13.39%	0.0092%
SOUTHERN CO/THE	SO	39,158.87	0.25%	4.49%	4.86%	9.45%	0.0239%
SIMON PROPERTY GROUP INC	SPG	50,538.45	0.33%	2.89%	7.59%	10.60%	0.0346%
STAPLES INC	SPLS	11,107.31	0.07%	2.85%	8.52%	11.49%	0.0082%
STERICYCLE INC	SRCL	10,121.67	0.07%	0.00%	16.00%	16.00%	0.0105%
SEMPRA ENERGY	SRE	20,406.90	0.13%	3.01%	6.75%	9.86%	0.0130%
SUNTRUST BANKS INC	STI	18,349.66	0.12%	1.04%	9.54%	10.62%	0.0126%
ST JUDE MEDICAL INC	STJ	13,717.59	0.09%	2.09%	10.21%	12.41%	0.0110%
STATE STREET CORP	STT	31,446.20	0.20%	1.51%	11.80%	13.40%	0.0272%
SEAGATE TECHNOLOGY	STX	16,744.40	0.11%	3.18%	6.17%	9.45%	0.0102%
CONSTELLATION BRANDS INC-A	STZ	9,854.60	0.06%	0.00%	13.62%	13.62%	0.0087%
STANLEY BLACK & DECKER INC	SWK	13,325.70	0.09%	2.45%	12.50%	15.10%	0.0130%
SOUTHWESTERN ENERGY CO	SWN	13,601.51	N/A	0.00%	NA	N/A	N/A
SAFEWAY INC	SWY	5,916.55	0.04%	2.79%	8.41%	11.31%	0.0043%
STRYKER CORP	SYK	25,429.55	0.16%	1.55%	8.34%	9.96%	0.0163%
SYMANTEC CORP	SYMC	16,600.81	0.11%	2.43%	7.00%	9.52%	0.0102%
SYSCO CORP	SYY	21,128.10	0.14%	3.13%	9.00%	12.27%	0.0167%
AT&T INC	T	192,657.81	1.24%	5.05%	5.43%	10.63%	0.1321%
MOLSON COORS BREWING CO -B	TAP	9,294.34	0.06%	2.68%	7.61%	10.40%	0.0062%
TERADATA CORP	TDC	9,135.69	0.06%	0.00%	14.80%	14.80%	0.0087%
TECO ENERGY INC	TE	3,820.76	0.02%	5.01%	4.50%	9.62%	0.0024%
INTEGRYS ENERGY GROUP INC	TEG	4,779.34	0.03%	4.50%	5.33%	9.96%	0.0031%
TE CONNECTIVITY LTD	TEL	19,716.18	0.13%	1.86%	15.00%	17.00%	0.0216%
TERADYNE INC	TER	3,534.49	0.02%	0.00%	11.75%	11.75%	0.0027%
TARGET CORP	TGT	46,561.98	0.30%	2.04%	11.22%	13.38%	0.0402%
TENET HEALTHCARE CORP	THC	4,534.38	0.03%	0.00%	10.25%	10.25%	0.0030%
TIFFANY & CO	TIF	9,826.13	0.06%	1.76%	13.05%	14.92%	0.0095%
TJX COMPANIES INC	TJX	37,651.34	0.24%	1.06%	11.69%	12.80%	0.0311%
TORCHMARK CORP	TMK	6,403.79	0.04%	0.95%	9.00%	10.00%	0.0041%
THERMO FISHER SCIENTIFIC INC	TMO	34,369.20	0.22%	0.68%	9.77%	10.48%	0.0232%
TRIPADVISOR INC	TRIP	8,752.80	0.06%	0.00%	17.50%	17.50%	0.0099%
T ROWE PRICE GROUP INC	TROW	20,085.77	0.13%	1.96%	13.76%	15.86%	0.0206%
TRAVELERS COS INC/THE	TRV	31,686.90	0.20%	2.32%	5.90%	8.28%	0.0169%
TYSON FOODS INC-CL A	TSN	9,648.16	0.06%	0.80%	8.50%	9.34%	0.0058%
TESORO CORP	TSO	7,497.00	0.05%	1.48%	26.32%	28.00%	0.0135%
TOTAL SYSTEM SERVICES INC	TSS	4,795.01	0.03%	1.52%	11.67%	13.28%	0.0041%
TIME WARNER CABLE	TWC	33,507.34	0.22%	2.26%	11.42%	13.80%	0.0298%
TIME WARNER INC	TWX	57,515.14	0.37%	1.85%	10.03%	11.98%	0.0445%
TEXAS INSTRUMENTS INC	TXN	41,582.20	0.27%	2.72%	9.67%	12.52%	0.0336%
TEXTRON INC	TXT	7,679.90	0.05%	0.29%	13.95%	14.26%	0.0071%
TYCO INTERNATIONAL LTD	TYC	16,277.14	0.11%	1.82%	11.00%	12.92%	0.0136%
UNITEDHEALTH GROUP INC	UNH	69,360.48	0.45%	1.40%	12.17%	13.65%	0.0611%
UNUM GROUP	UNM	8,426.91	0.05%	1.72%	9.50%	11.30%	0.0061%
UNION PACIFIC CORP	UNP	75,034.66	0.48%	1.75%	13.80%	15.67%	0.0759%
UNITED PARCEL SERVICE-CL B	UPS	81,326.68	0.52%	2.85%	11.54%	14.55%	0.0764%
URBAN OUTFITTERS INC	URBN	6,315.26	0.04%	0.00%	20.00%	20.00%	0.0082%
US BANCORP	USB	69,657.52	0.45%	2.35%	14.01%	16.52%	0.0743%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
UNITED TECHNOLOGIES CORP	UTX	91,773.79	0.59%	2.20%	12.86%	15.20%	0.0900%
VISA INC-CLASS A SHARES	V	123,959.34	0.80%	0.67%	18.88%	19.61%	0.1569%
VARIAN MEDICAL SYSTEMS INC	VAR	7,521.57	0.05%	0.00%	11.95%	11.95%	0.0058%
VF CORP	VFC	21,856.52	0.14%	1.78%	12.00%	13.89%	0.0196%
VIACOM INC-CLASS B	VIAB	34,939.34	0.23%	1.56%	11.21%	12.86%	0.0290%
VALERO ENERGY CORP	VLO	19,556.81	0.13%	2.19%	6.71%	8.98%	0.0113%
VULCAN MATERIALS CO	VMC	6,585.94	0.04%	0.08%	8.75%	8.83%	0.0038%
VORNADO REALTY TRUST	VNO	16,255.87	0.10%	3.36%	6.18%	9.64%	0.0101%
VERISIGN INC	VRSN	6,940.29	0.04%	0.00%	12.33%	12.33%	0.0055%
VENTAS INC	VTR	20,682.84	0.13%	3.79%	4.61%	8.48%	0.0113%
VERIZON COMMUNICATIONS INC	VZ	144,223.02	0.93%	4.13%	8.01%	12.30%	0.1145%
WALGREEN CO	WAG	46,078.38	0.30%	2.25%	13.14%	15.54%	0.0462%
WATERS CORP	WAT	8,956.95	0.06%	0.00%	11.26%	11.26%	0.0065%
WESTERN DIGITAL CORP	WDC	16,040.96	0.10%	1.35%	5.00%	6.39%	0.0066%
WISCONSIN ENERGY CORP	WEC	9,728.13	0.06%	3.20%	4.67%	7.94%	0.0050%
WELLS FARGO & CO	WFC	225,784.98	1.46%	2.63%	9.23%	11.98%	0.1745%
WHOLE FOODS MARKET INC	WFM	20,855.37	0.13%	1.66%	17.62%	19.43%	0.0262%
WHIRLPOOL CORP	WHR	9,765.16	0.06%	2.03%	26.04%	28.33%	0.0179%
WINDSTREAM CORP	WIN	4,831.01	0.03%	12.27%	-3.12%	8.96%	0.0028%
WELLPOINT INC	WLP	25,650.96	0.17%	1.76%	11.00%	12.85%	0.0213%
WASTE MANAGEMENT INC	WM	19,647.76	0.13%	3.47%	6.05%	9.63%	0.0122%
WILLIAMS COS INC	WMB	23,088.69	0.15%	4.28%	6.25%	10.66%	0.0159%
WAL-MART STORES INC	WMT	254,368.48	1.64%	2.40%	9.20%	11.71%	0.1923%
WASHINGTON POST-CLASS B	WPO	3,824.54	N/A	0.00%	NA	N/A	N/A
WPX ENERGY INC	WPX	3,974.54	N/A	0.00%	NA	N/A	N/A
WESTERN UNION CO	WU	9,732.74	0.06%	2.90%	11.14%	14.20%	0.0089%
WEYERHAEUSER CO	WY	17,011.05	0.11%	2.59%	5.50%	8.16%	0.0090%
WYNDHAM WORLDWIDE CORP	WYN	8,148.27	0.05%	1.93%	19.70%	21.82%	0.0115%
WYNN RESORTS LTD	WYNN	13,209.53	0.09%	3.06%	9.00%	12.20%	0.0104%
UNITED STATES STEEL CORP	X	2,589.91	0.02%	1.11%	6.00%	7.15%	0.0012%
XCEL ENERGY INC	XEL	14,574.08	0.09%	3.78%	4.80%	8.67%	0.0082%
XL GROUP PLC	XL	9,273.39	0.06%	1.71%	10.00%	11.80%	0.0071%
XILINX INC	XLNX	11,340.85	0.07%	2.27%	12.75%	15.17%	0.0111%
EXXON MOBIL CORP	XOM	415,291.50	2.68%	2.63%	15.32%	18.15%	0.4865%
DENTSPLY INTERNATIONAL INC	XRAY	6,016.44	0.04%	0.59%	9.80%	10.41%	0.0040%
XEROX CORP	XRX	12,058.00	N/A	2.16%	NA	N/A	N/A
XYLEM INC	XYL	5,388.27	0.03%	1.61%	7.70%	9.37%	0.0033%
YAHOO! INC	YHOO	29,480.14	0.19%	0.00%	9.16%	9.16%	0.0174%
YUM! BRANDS INC	YUM	31,776.55	0.21%	1.96%	12.16%	14.23%	0.0292%
ZIONS BANCORPORATION	ZION	5,521.97	0.04%	0.40%	7.75%	8.17%	0.0029%
ZIMMER HOLDINGS INC	ZMH	13,292.32	0.09%	0.97%	10.57%	11.59%	0.0099%
ZOETIS INC	ZTS	15,675.00	0.10%	0.83%	12.85%	13.73%	0.0139%
	Total Market Capitali:	15,493,763.03					13.44%

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] - [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

[1] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
12.72%	3.46%	9.27%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
AGILENT TECHNOLOGIES INC	A	14,871.03	0.10%	1.11%	6.50%	7.65%	0.0077%
ALCOA INC	AA	8,244.90	0.06%	1.56%	20.00%	21.72%	0.0122%
APPLE INC	AAPL	395,591.50	2.70%	2.90%	14.50%	17.61%	0.4747%
ABBVIE INC	ABBV	66,850.09	0.46%	3.79%	0.00%	3.79%	0.0173%
AMERISOURCEBERGEN CORP	ABC	12,719.51	0.09%	1.53%	12.50%	14.13%	0.0122%
ABBOTT LABORATORIES	ABT	53,391.09	0.36%	1.64%	-5.50%	-3.91%	-0.0142%
ACE LTD	ACE	30,264.01	0.21%	2.29%	5.00%	7.35%	0.0152%
ACCENTURE PLC-CL A	ACN	46,949.75	0.32%	2.23%	10.50%	12.85%	0.0411%
ACTAVIS INC	ACT	15,833.52	0.11%	0.00%	14.00%	14.00%	0.0151%
ADOBE SYSTEMS INC	ADBE	23,351.67	0.16%	0.00%	4.00%	4.00%	0.0064%
ANALOG DEVICES INC	ADI	14,076.98	0.10%	2.98%	9.00%	12.11%	0.0116%
ARCHER-DANIELS-MIDLAND CO	ADM	22,939.79	0.16%	2.18%	6.00%	8.25%	0.0129%
AUTOMATIC DATA PROCESSING	ADP	34,073.43	0.23%	2.56%	8.00%	10.66%	0.0248%
AUTODESK INC	ADSK	7,528.55	0.05%	0.00%	15.00%	15.00%	0.0077%
ADT CORP/THE	ADT	8,630.48	0.06%	1.27%	0.00%	1.27%	0.0007%
AMEREN CORPORATION	AEE	8,221.71	0.06%	4.72%	-0.50%	4.21%	0.0024%
AMERICAN ELECTRIC POWER	AEP	21,607.56	0.15%	4.50%	4.50%	9.10%	0.0134%
AES CORP	AES	8,830.79	0.06%	1.35%	21.50%	23.00%	0.0138%
AETNA INC	AET	20,248.17	0.14%	1.29%	9.50%	10.85%	0.0150%
AFLAC INC	AFL	26,377.01	0.18%	2.58%	8.00%	10.68%	0.0192%
ALLERGAN INC	AGN	24,957.96	0.17%	0.24%	12.50%	12.76%	0.0217%
AMERICAN INTERNATIONAL GROUP	AIG	65,283.98	0.44%	0.00%	0.00%	0.00%	0.0000%
APARTMENT INVT & MGMT CO -A	AIV	-	0.00%	3.20%	0.00%	3.20%	0.0000%
ASSURANT INC	AIZ	3,955.73	0.03%	1.98%	6.50%	8.54%	0.0023%
AKAMAI TECHNOLOGIES INC	AKAM	7,591.99	0.05%	0.00%	14.00%	14.00%	0.0072%
ALLSTATE CORP	ALL	22,683.96	0.15%	2.06%	15.50%	17.72%	0.0274%
ALTERA CORP	ALTR	10,647.86	0.07%	1.80%	3.00%	4.83%	0.0035%
ALEXION PHARMACEUTICALS INC	ALXN	18,733.08	0.13%	0.00%	26.50%	26.50%	0.0338%
APPLIED MATERIALS INC	AMAT	18,024.00	0.12%	2.67%	9.50%	12.30%	0.0151%
ADVANCED MICRO DEVICES	AMD	2,898.84	0.02%	0.00%	-5.50%	-5.50%	-0.0011%
AMGEN INC	AMGN	71,819.17	0.49%	2.03%	8.50%	10.62%	0.0520%
AMERIPRISE FINANCIAL INC	AMP	16,424.04	0.11%	2.56%	11.50%	14.21%	0.0159%
AMERICAN TOWER CORP	AMT	28,632.59	0.20%	1.58%	22.50%	24.26%	0.0473%
AMAZON.COM INC	AMZN	129,233.70	0.88%	0.00%	51.00%	51.00%	0.4492%
AUTONATION INC	AN	5,491.25	0.04%	0.00%	18.00%	18.00%	0.0067%
ABERCROMBIE & FITCH CO-CL A	ANF	3,723.45	0.03%	1.68%	22.00%	23.86%	0.0061%
AON PLC	AON	19,972.63	0.14%	1.08%	15.00%	16.16%	0.0220%
APACHE CORP	APA	31,437.56	0.21%	1.00%	11.50%	12.56%	0.0269%
ANADARKO PETROLEUM CORP	APC	43,586.70	0.30%	0.41%	74.00%	74.56%	0.2215%
AIR PRODUCTS & CHEMICALS INC	APD	19,039.28	0.13%	3.11%	7.50%	10.73%	0.0139%
AMPHENOL CORP-CL A	APH	12,624.00	0.09%	0.53%	8.50%	9.05%	0.0078%
AIRGAS INC	ARG	7,372.73	0.05%	2.09%	15.50%	17.75%	0.0089%
ALLEGHENY TECHNOLOGIES INC	ATI	2,806.88	0.02%	2.77%	21.50%	24.57%	0.0047%
AVALONBAY COMMUNITIES INC	AVB	-	0.00%	3.26%	0.00%	3.26%	0.0000%
AVON PRODUCTS INC	AVP	9,069.20	0.06%	1.15%	19.00%	20.26%	0.0125%
AVERY DENNISON CORP	AVY	4,359.97	0.03%	2.66%	7.00%	9.75%	0.0029%
AMERICAN EXPRESS CO	AXP	81,888.84	0.56%	1.23%	9.00%	10.29%	0.0574%
AUTOZONE INC	AZO	15,035.45	0.10%	0.00%	15.00%	15.00%	0.0154%
BOEING CO/THE	BA	78,023.65	0.53%	1.89%	8.00%	9.97%	0.0530%
BANK OF AMERICA CORP	BAC	138,851.10	0.95%	0.31%	0.00%	0.31%	0.0029%
BAXTER INTERNATIONAL INC	BAX	37,652.83	0.26%	2.82%	8.50%	11.44%	0.0294%
BED BATH & BEYOND INC	BBBY	15,974.28	0.11%	0.00%	12.50%	12.50%	0.0136%
BB&T CORP	BBT	23,968.20	0.16%	2.69%	11.50%	14.34%	0.0234%
BEST BUY CO INC	BBY	9,995.06	0.07%	2.31%	1.50%	3.83%	0.0026%
CR BARD INC	BCR	8,635.61	0.06%	0.78%	8.00%	8.81%	0.0052%
BECTON DICKINSON AND CO	BDX	18,997.75	0.13%	2.03%	8.50%	10.62%	0.0137%
BEAM INC	BEAM	10,221.28	0.07%	1.42%	10.50%	11.99%	0.0084%
FRANKLIN RESOURCES INC	BEN	29,329.60	0.20%	0.88%	9.00%	9.92%	0.0198%
BROWN-FORMAN CORP-CLASS B	BF/B	15,327.71	0.10%	1.56%	8.50%	10.13%	0.0106%
BAKER HUGHES INC	BHI	21,039.80	0.14%	1.26%	13.00%	14.34%	0.0206%
BIOGEN IDEC INC	BIIB	51,628.84	0.35%	0.00%	12.50%	12.50%	0.0440%
BANK OF NEW YORK MELLON CORP	BK	33,113.23	0.23%	2.10%	10.00%	12.21%	0.0275%
BLACKROCK INC	BLK	43,675.50	0.30%	2.63%	8.00%	10.74%	0.0320%
BALL CORP	BLL	6,262.85	0.04%	1.24%	10.00%	11.30%	0.0048%
BMC SOFTWARE INC	BMC	6,450.04	0.04%	0.00%	8.00%	8.00%	0.0035%
BEMIS COMPANY	BMS	4,031.82	0.03%	2.65%	10.50%	13.29%	0.0037%
BRISTOL-MYERS SQUIBB CO	BMY	71,155.31	0.48%	3.23%	10.00%	13.39%	0.0649%
BROADCOM CORP-CL A	BRCM	19,077.11	0.13%	1.32%	3.00%	4.34%	0.0056%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
BERKSHIRE HATHAWAY INC-CL B	BRK/B	-	0.00%	0.00%	0.00%	0.00%	0.0000%
BOSTON SCIENTIFIC CORP	BSX	12,356.28	0.08%	0.00%	7.50%	7.50%	0.0063%
PEABODY ENERGY CORP	BTU	3,949.64	0.03%	2.32%	-0.50%	1.81%	0.0005%
BORGWARNER INC	BWA	9,761.10	0.07%	0.00%	13.00%	13.00%	0.0086%
BOSTON PROPERTIES INC	BXP	-	0.00%	2.53%	0.00%	2.53%	0.0000%
CITIGROUP INC	C	145,054.30	0.99%	0.44%	14.00%	14.47%	0.1430%
CA INC	CA	12,643.96	0.09%	3.57%	7.00%	10.69%	0.0092%
CONAGRA FOODS INC	CAG	14,864.86	0.10%	2.80%	13.00%	15.98%	0.0162%
CARDINAL HEALTH INC	CAH	16,176.60	0.11%	2.69%	11.00%	13.84%	0.0153%
CAMERON INTERNATIONAL CORP	CAM	15,481.13	0.11%	0.00%	15.50%	15.50%	0.0164%
CATERPILLAR INC	CAT	53,709.97	0.37%	2.93%	10.00%	13.08%	0.0479%
CHUBB CORP	CB	22,063.31	0.15%	2.07%	8.00%	10.15%	0.0153%
CBRE GROUP INC - A	CBG	7,626.56	0.05%	0.00%	10.50%	10.50%	0.0055%
CBS CORP-CLASS B NON VOTING	CBS	30,502.88	0.21%	0.97%	13.00%	14.03%	0.0292%
COCA-COLA ENTERPRISES	CCE	9,473.63	0.06%	2.37%	8.50%	10.97%	0.0071%
CROWN CASTLE INTL CORP	CCI	21,269.02	0.14%	0.00%	32.50%	32.50%	0.0471%
CARNIVAL CORP	CCL	27,008.75	0.18%	2.87%	6.00%	8.96%	0.0165%
CELGENE CORP	CELG	50,560.83	0.34%	0.00%	10.50%	10.50%	0.0362%
CERNER CORP	CERN	16,688.08	0.11%	0.00%	16.50%	16.50%	0.0188%
CF INDUSTRIES HOLDINGS INC	CF	10,601.84	0.07%	0.97%	8.50%	9.51%	0.0069%
CAREFUSION CORP	CFN	8,263.19	0.06%	0.00%	11.50%	11.50%	0.0065%
CHESAPEAKE ENERGY CORP	CHK	14,014.21	0.10%	1.67%	2.00%	3.69%	0.0035%
C.H. ROBINSON WORLDWIDE INC	CHRW	9,051.05	0.06%	2.48%	8.00%	10.58%	0.0065%
CIGNA CORP	CI	20,833.03	0.14%	0.06%	9.50%	9.56%	0.0136%
CINCINNATI FINANCIAL CORP	CINF	7,550.16	0.05%	3.52%	13.50%	17.26%	0.0089%
COLGATE-PALMOLIVE CO	CL	53,930.85	0.37%	2.40%	10.50%	13.03%	0.0479%
CLIFFS NATURAL RESOURCES INC	CLF	2,461.77	0.02%	3.73%	-4.00%	-0.34%	-0.0001%
CLOROX COMPANY	CLX	10,949.66	0.07%	3.46%	10.50%	14.14%	0.0106%
COMERICA INC	CMA	7,645.72	0.05%	1.66%	12.50%	14.26%	0.0074%
COMCAST CORP-CLASS A	CMCSA	108,365.00	0.74%	1.90%	10.50%	12.50%	0.0923%
CME GROUP INC	CME	25,148.29	0.17%	2.38%	7.00%	9.46%	0.0162%
CHIPOTLE MEXICAN GRILL INC	CMG	11,892.81	0.08%	0.00%	18.00%	18.00%	0.0146%
CUMMINS INC	CMI	20,505.87	0.14%	1.91%	10.50%	12.51%	0.0175%
CMS ENERGY CORP	CMS	7,070.28	0.05%	3.95%	5.50%	9.56%	0.0046%
CENTERPOINT ENERGY INC	CNP	10,010.30	0.07%	3.60%	4.50%	8.18%	0.0056%
CONSOL ENERGY INC	CNX	6,070.93	0.04%	1.88%	9.00%	10.96%	0.0045%
CAPITAL ONE FINANCIAL CORP	COF	37,105.56	0.25%	1.88%	3.00%	4.91%	0.0124%
CABOT OIL & GAS CORP	COG	15,079.63	0.10%	0.11%	28.00%	28.13%	0.0289%
COACH INC	COH	15,861.65	0.11%	2.39%	11.00%	13.52%	0.0146%
ROCKWELL COLLINS INC	COL	8,639.16	0.06%	1.89%	7.50%	9.46%	0.0056%
CONOCOPHILLIPS	COP	75,609.35	0.52%	4.27%	3.50%	7.84%	0.0404%
COSTCO WHOLESALE CORP	COST	48,432.40	0.33%	1.13%	11.50%	12.69%	0.0419%
COVIDIEN PLC	COV	27,161.53	0.19%	1.90%	7.50%	9.47%	0.0175%
CAMPBELL SOUP CO	CPB	13,796.64	0.09%	2.62%	4.50%	7.18%	0.0067%
SALESFORCE.COM INC	CRM	22,744.50	0.15%	0.00%	0.00%	0.00%	0.0000%
COMPUTER SCIENCES CORP	CSC	6,998.86	0.05%	1.76%	3.50%	5.29%	0.0025%
CISCO SYSTEMS INC	CSCO	130,695.90	0.89%	2.77%	9.00%	11.89%	0.1059%
CSX CORP	CSX	23,535.74	0.16%	2.61%	10.50%	13.25%	0.0212%
CINTAS CORP	CTAS	5,629.30	0.04%	1.40%	11.00%	12.48%	0.0048%
CENTURYLINK INC	CTL	21,710.94	0.15%	6.12%	8.00%	14.36%	0.0213%
COGNIZANT TECH SOLUTIONS-A	CTSH	19,588.93	0.13%	0.00%	20.50%	20.50%	0.0274%
CITRIX SYSTEMS INC	CTXS	11,574.68	0.08%	0.00%	15.50%	15.50%	0.0122%
CABLEVISION SYSTEMS-NY GRP-A	CVC	5,013.37	0.03%	3.20%	11.00%	14.38%	0.0049%
CVS CAREMARK CORP	CVS	71,592.41	0.49%	1.54%	11.50%	13.13%	0.0641%
CHEVRON CORP	CVX	230,893.40	1.57%	3.36%	7.00%	10.48%	0.1649%
DOMINION RESOURCES INC/VA	D	32,546.26	0.22%	4.05%	6.00%	10.17%	0.0226%
DU PONT (E.I.) DE NEMOURS	DD	48,218.11	0.33%	3.47%	8.00%	11.61%	0.0381%
DEERE & CO	DE	31,427.69	0.21%	2.52%	8.50%	11.13%	0.0238%
DELL INC	DELL	23,359.05	0.16%	2.40%	2.50%	4.93%	0.0078%
DISCOVER FINANCIAL SERVICES	DFS	23,824.17	0.16%	1.66%	8.50%	10.23%	0.0166%
DOLLAR GENERAL CORP	DG	16,733.16	0.11%	0.00%	16.00%	16.00%	0.0182%
QUEST DIAGNOSTICS INC	DGX	9,487.23	0.06%	2.00%	7.00%	9.07%	0.0059%
DR HORTON INC	DHI	6,754.47	0.05%	0.19%	31.50%	31.72%	0.0146%
DANAHER CORP	DHR	44,076.95	0.30%	0.16%	12.50%	12.67%	0.0381%
WALT DISNEY CO/THE	DIS	114,498.00	0.78%	1.18%	11.00%	12.24%	0.0955%
DISCOVERY COMMUNICATIONS-A	DISCA	19,731.37	0.13%	0.00%	14.00%	14.00%	0.0188%
DELPHI AUTOMOTIVE PLC	DLPH	16,135.79	0.11%	1.32%	0.00%	1.32%	0.0015%
DOLLAR TREE INC	DLTR	11,651.03	0.08%	0.00%	15.50%	15.50%	0.0123%
DUN & BRADSTREET CORP	DNB	3,914.71	0.03%	1.63%	7.00%	8.69%	0.0023%
DENBURY RESOURCES INC	DNR	6,375.77	0.04%	0.00%	13.00%	13.00%	0.0056%
DIAMOND OFFSHORE DRILLING	DO	9,440.48	0.06%	5.16%	6.50%	11.83%	0.0076%
DOVER CORP	DOV	13,103.07	0.09%	1.83%	13.00%	14.95%	0.0133%
DOW CHEMICAL CO/THE	DOW	39,226.94	0.27%	4.69%	13.00%	17.99%	0.0481%
DR PEPPER SNAPPLE GROUP INC	DPS	9,502.97	0.06%	3.31%	7.50%	10.93%	0.0071%
DARDEN RESTAURANTS INC	DRI	6,615.22	0.05%	4.32%	10.00%	14.54%	0.0066%
DTE ENERGY COMPANY	DTE	11,463.30	0.08%	3.98%	4.00%	8.06%	0.0063%
DIRECTV	DTV	35,472.85	0.24%	0.00%	16.50%	16.50%	0.0399%
DUKE ENERGY CORP	DUK	47,577.34	0.32%	4.63%	4.00%	8.72%	0.0283%
DAVITA HEALTHCARE PARTNERS I	DVA	12,039.46	0.08%	0.00%	14.50%	14.50%	0.0119%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
DEVON ENERGY CORPORATION	DVN	21,721.00	0.15%	1.65%	7.50%	9.21%	0.0136%
ELECTRONIC ARTS INC	EA	7,016.31	0.05%	0.00%	15.50%	15.50%	0.0074%
EBAY INC	EBAY	68,855.15	0.47%	0.00%	15.00%	15.00%	0.0704%
ECOLAB INC	ECL	25,406.63	0.17%	1.07%	15.00%	16.15%	0.0280%
CONSOLIDATED EDISON INC	ED	16,833.88	0.11%	4.32%	2.50%	6.87%	0.0079%
EQUIFAX INC	EFX	7,119.02	0.05%	1.49%	10.50%	12.07%	0.0059%
EDISON INTERNATIONAL	EIX	15,186.05	0.10%	2.96%	2.50%	5.50%	0.0057%
ESTEE LAUDER COMPANIES-CL A	EL	26,072.69	0.18%	1.07%	13.50%	14.64%	0.0260%
EMC CORP/MA	EMC	50,357.14	0.34%	1.67%	11.50%	13.27%	0.0455%
EASTMAN CHEMICAL CO	EMN	10,994.31	0.07%	1.69%	11.50%	13.29%	0.0100%
EMERSON ELECTRIC CO	EMR	39,775.93	0.27%	2.97%	8.00%	11.09%	0.0301%
EOG RESOURCES INC	EOG	37,592.97	0.26%	0.55%	19.00%	19.60%	0.0502%
EQUITY RESIDENTIAL	EQR	-	0.00%	2.89%	0.00%	2.89%	0.0000%
EQT CORP	EQT	11,986.66	0.08%	0.15%	17.00%	17.16%	0.0140%
EXPRESS SCRIPTS HOLDING CO	ESRX	50,989.29	0.35%	0.00%	14.00%	14.00%	0.0486%
ENSCO PLC-CL A	ESV	13,218.89	0.09%	3.52%	16.00%	19.80%	0.0178%
E*TRADE FINANCIAL CORP	ETFC	3,687.94	0.03%	0.00%	0.00%	0.00%	0.0000%
EATON CORP PLC	ETN	31,328.68	0.21%	2.54%	10.50%	13.17%	0.0281%
ENTERGY CORP	ETR	12,340.20	0.08%	4.79%	-3.50%	1.21%	0.0010%
EDWARDS LIFESCIENCES CORP	EW	7,405.88	0.05%	0.00%	17.00%	17.00%	0.0086%
EXELON CORP	EXC	25,743.94	0.18%	4.12%	-2.50%	1.57%	0.0028%
EXPEDITORS INTL WASH INC	EXPD	7,841.92	0.05%	1.58%	7.00%	8.64%	0.0046%
EXPEDIA INC	EXPE	8,348.20	0.06%	0.88%	9.50%	10.42%	0.0059%
FORD MOTOR CO	F	64,589.71	0.44%	2.44%	10.00%	12.56%	0.0553%
FASTENAL CO	FAST	13,436.91	0.09%	1.77%	15.00%	16.90%	0.0155%
FREEPORT-MCMORAN COPPER	FCX	26,296.00	0.18%	4.66%	7.50%	12.33%	0.0221%
FAMILY DOLLAR STORES	FDO	7,278.76	0.05%	1.64%	11.50%	13.23%	0.0066%
FEDEX CORP	FDX	30,980.19	0.21%	0.61%	8.50%	9.14%	0.0193%
FIRSTENERGY CORP	FE	15,122.69	0.10%	6.08%	3.50%	9.69%	0.0100%
F5 NETWORKS INC	FFIV	5,433.30	0.04%	0.00%	13.50%	13.50%	0.0050%
FIDELITY NATIONAL INFORMATIO	FIS	12,596.43	0.09%	2.04%	10.00%	12.14%	0.0104%
FISERV INC	FISV	11,710.94	0.08%	0.00%	6.50%	6.50%	0.0052%
FIFTH THIRD BANCORP	FITB	16,067.21	0.11%	2.61%	10.00%	12.74%	0.0140%
FLIR SYSTEMS INC	FLIR	3,902.28	0.03%	1.38%	9.50%	10.95%	0.0029%
FLUOR CORP	FLR	9,489.91	0.06%	1.10%	12.00%	13.17%	0.0085%
FLOWSERVE CORP	FLS	7,706.26	0.05%	1.03%	11.50%	12.59%	0.0066%
FMC CORP	FMC	8,399.22	0.06%	0.96%	13.50%	14.52%	0.0083%
FOSSIL GROUP INC	FOSL	6,230.52	0.04%	0.00%	13.50%	13.50%	0.0057%
TWENTY-FIRST CENTURY-CL A-WI	FOXAV	N/A	N/A	N/A	N/A	N/A	N/A
FOREST LABORATORIES INC	FRX	11,147.65	0.08%	0.00%	-5.00%	-5.00%	-0.0038%
FIRST SOLAR INC	FSLR	3,991.27	0.03%	0.00%	-5.00%	-5.00%	-0.0014%
FMC TECHNOLOGIES INC	FTI	13,253.21	0.09%	0.00%	20.50%	20.50%	0.0185%
FRONTIER COMMUNICATIONS CORP	FTR	3,952.60	0.03%	10.10%	9.50%	20.08%	0.0054%
AGL RESOURCES INC	GAS	5,026.13	0.03%	4.42%	9.00%	13.62%	0.0047%
GANNETT CO	GCI	5,836.59	0.04%	3.14%	5.00%	8.22%	0.0033%
GENERAL DYNAMICS CORP	GD	27,565.73	0.19%	2.86%	2.50%	5.40%	0.0101%
GENERAL ELECTRIC CO	GE	236,892.10	1.61%	3.32%	13.00%	16.54%	0.2669%
GILEAD SCIENCES INC	GILD	79,237.43	0.54%	0.00%	9.50%	9.50%	0.0513%
GENERAL MILLS INC	GIS	31,538.48	0.21%	3.11%	7.50%	10.73%	0.0231%
CORNING INC	GLW	21,034.44	0.14%	2.80%	3.50%	6.35%	0.0091%
GENERAL MOTORS CO	GM	46,930.18	0.32%	0.00%	10.00%	10.00%	0.0320%
GAMESTOP CORP-CLASS A	GME	5,043.22	0.03%	2.64%	9.00%	11.76%	0.0040%
GENWORTH FINANCIAL INC-CL A	GNW	5,861.77	0.04%	0.00%	28.00%	28.00%	0.0112%
GOOGLE INC-CL A	GOOG	293,415.40	2.00%	0.00%	13.00%	13.00%	0.2599%
GENUINE PARTS CO	GPC	12,840.48	0.09%	2.60%	10.00%	12.73%	0.0111%
GAP INC/THE	GPS	19,986.74	0.14%	1.40%	12.00%	13.48%	0.0184%
GARMIN LTD	GRMN	6,863.68	0.05%	5.27%	-1.50%	3.73%	0.0017%
GOLDMAN SACHS GROUP INC	GS	69,315.43	0.47%	1.33%	13.00%	14.42%	0.0681%
GOODYEAR TIRE & RUBBER CO	GT	3,778.71	0.03%	0.00%	16.50%	16.50%	0.0042%
WW GRAINGER INC	GWW	17,744.85	0.12%	1.46%	14.50%	16.07%	0.0194%
HALLIBURTON CO	HAL	39,707.15	0.27%	1.17%	11.50%	12.74%	0.0345%
HARMAN INTERNATIONAL	HAR	3,626.87	0.02%	2.25%	14.50%	16.91%	0.0042%
HASBRO INC	HAS	5,953.15	0.04%	3.48%	6.00%	9.58%	0.0039%
HUNTINGTON BANCSHARES INC	HBAN	6,877.81	0.05%	2.44%	11.50%	14.08%	0.0066%
HUDSON CITY BANCORP INC	HCBK	4,649.98	0.03%	1.71%	68.00%	70.29%	0.0223%
HEALTH CARE REIT INC	HCN	-	0.00%	4.81%	96.00%	103.12%	0.0000%
HCP INC	HCP	-	0.00%	4.79%	0.00%	4.79%	0.0000%
HOME DEPOT INC	HD	113,563.50	0.77%	2.01%	12.50%	14.64%	0.1133%
HESS CORP	HES	23,069.56	0.16%	0.60%	6.00%	6.62%	0.0104%
HARTFORD FINANCIAL SVCS GRP	HIG	13,186.33	0.09%	1.98%	17.00%	19.15%	0.0172%
HARLEY-DAVIDSON INC	HOG	12,269.53	0.08%	1.54%	16.00%	17.66%	0.0148%
HONEYWELL INTERNATIONAL INC	HON	61,770.33	0.42%	2.09%	10.50%	12.70%	0.0535%
STARWOOD HOTELS & RESORTS	HOT	12,247.24	0.08%	1.99%	14.00%	16.13%	0.0135%
HELMERICH & PAYNE	HP	6,790.70	0.05%	3.13%	14.00%	17.35%	0.0080%
HEWLETT-PACKARD CO	HPQ	48,471.50	0.33%	2.34%	58.00%	61.02%	0.2016%
H&R BLOCK INC	HRB	7,603.15	0.05%	2.87%	7.00%	9.97%	0.0052%
HORMEL FOODS CORP	HRL	10,218.89	0.07%	1.87%	10.00%	11.96%	0.0083%
HARRIS CORP	HRS	5,358.75	0.04%	3.10%	1.50%	4.62%	0.0017%
HOSPIRA INC	HSP	6,359.63	0.04%	0.00%	4.50%	4.50%	0.0020%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
HOST HOTELS & RESORTS INC	HST	-	0.00%	2.59%	0.00%	2.59%	0.0000%
HERSHEY CO/THE	HSY	19,939.04	0.14%	1.93%	11.00%	13.04%	0.0177%
HUMANA INC	HUM	13,080.46	0.09%	1.30%	8.00%	9.35%	0.0083%
INTL BUSINESS MACHINES CORP	IBM	214,274.40	1.46%	1.99%	8.50%	10.57%	0.1544%
INTERCONTINENTALEXCHANGE INC	ICE	12,725.90	0.09%	0.00%	9.00%	9.00%	0.0078%
INTL FLAVORS & FRAGRANCES	IFF	6,307.23	0.04%	1.76%	8.00%	9.83%	0.0042%
INTL GAME TECHNOLOGY	IGT	4,318.14	0.03%	2.17%	13.50%	15.82%	0.0047%
INTEL CORP	INTC	117,564.50	0.80%	3.79%	7.50%	11.43%	0.0916%
INTUIT INC	INTU	18,510.83	0.13%	1.23%	13.00%	14.31%	0.0181%
INTERNATIONAL PAPER CO	IP	20,321.38	0.14%	2.62%	12.00%	14.78%	0.0205%
INTERPUBLIC GROUP OF COS INC	IPG	6,370.26	0.04%	2.09%	13.50%	15.73%	0.0068%
INGERSOLL-RAND PLC	IR	16,768.61	0.11%	1.50%	13.00%	14.60%	0.0167%
IRON MOUNTAIN INC	IRM	5,146.50	0.04%	4.00%	9.00%	13.18%	0.0046%
INTUITIVE SURGICAL INC	ISRG	20,088.74	0.14%	0.00%	13.00%	13.00%	0.0178%
ILLINOIS TOOL WORKS	ITW	30,976.21	0.21%	2.21%	9.00%	11.31%	0.0239%
INVESCO LTD	IVZ	13,984.12	0.10%	2.86%	17.00%	20.10%	0.0192%
JABIL CIRCUIT INC	JBL	4,186.60	0.03%	1.55%	14.50%	16.16%	0.0046%
JOHNSON CONTROLS INC	JCI	24,344.72	0.17%	2.14%	9.50%	11.74%	0.0195%
J.C. PENNEY CO INC	JCP	3,650.34	0.02%	0.00%	0.00%	0.00%	0.0000%
JDS UNIPHASE CORP	JDSU	3,441.24	0.02%	0.00%	10.00%	10.00%	0.0023%
JACOBS ENGINEERING GROUP INC	JEC	7,132.08	0.05%	0.00%	12.50%	12.50%	0.0061%
JOHNSON & JOHNSON	JNJ	243,258.60	1.66%	3.04%	6.50%	9.64%	0.1598%
JUNIPER NETWORKS INC	JNPR	9,860.37	0.07%	0.00%	12.50%	12.50%	0.0084%
JOY GLOBAL INC	JOY	5,136.75	0.04%	1.45%	5.50%	6.99%	0.0024%
JPMORGAN CHASE & CO	JPM	199,961.30	1.36%	2.86%	6.50%	9.47%	0.1291%
NORDSTROM INC	JWN	11,900.85	0.08%	2.02%	12.00%	14.14%	0.0115%
KELLOGG CO	K	23,811.96	0.16%	2.83%	8.00%	10.94%	0.0178%
KEYCORP	KEY	10,545.10	0.07%	1.93%	8.50%	10.51%	0.0076%
KIMCO REALTY CORP	KIM	-	0.00%	4.06%	0.00%	4.06%	0.0000%
KLA-TENCOR CORPORATION	KLAC	9,135.29	0.06%	2.91%	8.50%	11.53%	0.0072%
KIMBERLY-CLARK CORP	KMB	37,327.44	0.25%	3.34%	9.50%	13.00%	0.0331%
KINDER MORGAN INC	KMI	39,792.78	0.27%	3.96%	0.00%	3.96%	0.0107%
CARMAX INC	KMX	10,680.51	0.07%	0.00%	9.00%	9.00%	0.0066%
COCA-COLA CO/THE	KO	180,099.50	1.23%	2.77%	8.00%	10.88%	0.1335%
KROGER CO	KR	18,298.40	0.12%	1.91%	10.00%	12.01%	0.0150%
KRAFT FOODS GROUP INC	KRFT	32,999.03	0.22%	3.60%	0.00%	3.60%	0.0081%
KOHLS CORP	KSS	11,516.31	0.08%	2.74%	8.00%	10.85%	0.0085%
KANSAS CITY SOUTHERN	KSU	12,116.61	0.08%	0.78%	16.50%	17.34%	0.0143%
LOEWS CORP	L	17,256.89	0.12%	0.57%	13.00%	13.61%	0.0160%
LEGGETT & PLATT INC	LEG	4,429.71	0.03%	3.74%	13.00%	16.98%	0.0051%
LENNAR CORP-A	LEN	6,798.76	0.05%	0.45%	38.50%	39.04%	0.0181%
LABORATORY CRP OF AMER HLDGS	LH	9,137.09	0.06%	0.00%	9.50%	9.50%	0.0059%
LIFE TECHNOLOGIES CORP	LIFE	12,692.25	0.09%	0.00%	8.50%	8.50%	0.0074%
L-3 COMMUNICATIONS HOLDINGS	LLL	7,721.98	0.05%	2.57%	3.50%	6.11%	0.0032%
LINEAR TECHNOLOGY CORP	LLTC	8,620.03	0.06%	2.81%	6.00%	8.89%	0.0052%
ELI LILLY & CO	LLY	54,356.77	0.37%	3.91%	-4.50%	-0.68%	-0.0025%
LEGG MASON INC	LM	3,993.37	0.03%	1.68%	15.50%	17.31%	0.0047%
LOCKHEED MARTIN CORP	LMT	34,486.24	0.24%	4.48%	1.50%	6.01%	0.0141%
LINCOLN NATIONAL CORP	LNC	9,927.54	0.07%	1.46%	6.00%	7.50%	0.0051%
LORILLARD INC	LO	16,764.30	0.11%	4.96%	11.00%	16.23%	0.0185%
LOWE'S COS INC	LOW	46,044.16	0.31%	1.70%	15.50%	17.33%	0.0544%
LAM RESEARCH CORP	LRCX	7,321.54	0.05%	0.00%	10.50%	10.50%	0.0052%
LSI CORP	LSI	3,973.50	0.03%	0.00%	31.00%	31.00%	0.0084%
L BRANDS INC	LTD	14,218.80	0.10%	2.44%	9.50%	12.06%	0.0117%
LEUCADIA NATIONAL CORP	LUK	N/A	N/A	N/A	N/A	N/A	N/A
SOUTHWEST AIRLINES CO	LUV	9,180.38	0.06%	1.26%	14.00%	15.35%	0.0096%
LYONDELLBASELL INDU-CL A	LYB	38,038.73	0.26%	3.16%	11.50%	14.84%	0.0385%
MACY'S INC	M	18,599.50	0.13%	2.06%	13.50%	15.70%	0.0199%
MASTERCARD INC-CLASS A	MA	71,460.04	0.49%	0.41%	14.50%	14.94%	0.0728%
MACERICH CO/THE	MAC	-	0.00%	3.79%	0.00%	3.79%	0.0000%
MARRIOTT INTERNATIONAL -CL A	MAR	12,464.79	0.08%	1.69%	14.00%	15.81%	0.0134%
MASCO CORP	MAS	6,968.04	0.05%	1.50%	52.50%	54.39%	0.0258%
MATTEL INC	MAT	15,509.84	0.11%	3.21%	10.50%	13.88%	0.0147%
MCDONALD'S CORP	MCD	100,605.70	0.69%	3.07%	8.00%	11.19%	0.0767%
MICROCHIP TECHNOLOGY INC	MCHP	7,426.64	0.05%	3.76%	9.50%	13.44%	0.0068%
MCKESSON CORP	MCK	25,974.15	0.18%	0.70%	10.50%	11.24%	0.0199%
MOODY'S CORP	MCO	13,382.92	0.09%	1.33%	9.50%	10.89%	0.0099%
MONDELEZ INTERNATIONAL INC-A	MDLZ	50,999.64	0.35%	1.82%	4.50%	6.36%	0.0221%
MEDTRONIC INC	MDT	52,241.37	0.36%	2.17%	5.50%	7.73%	0.0275%
METLIFE INC	MET	50,629.46	0.35%	2.38%	8.50%	10.98%	0.0379%
MCGRAW HILL FINANCIAL INC	MHFI	14,878.15	0.10%	2.10%	0.00%	2.10%	0.0021%
MEAD JOHNSON NUTRITION CO	MJN	13,942.13	0.10%	1.98%	10.00%	12.08%	0.0115%
MCCORMICK & CO-NON VTG SHRS	MKC	9,129.40	0.06%	2.05%	10.00%	12.15%	0.0076%
MARSH & MCLENNAN COS	MMC	22,154.00	0.15%	2.48%	13.00%	15.64%	0.0236%
3M CO	MMM	75,541.73	0.51%	2.32%	8.00%	10.41%	0.0536%
MONSTER BEVERAGE CORP	MNST	9,980.71	0.07%	0.00%	17.00%	17.00%	0.0116%
ALTRIA GROUP INC	MO	71,086.47	0.48%	5.13%	11.00%	16.41%	0.0795%
MOLEX INC	MOLX	5,220.77	0.04%	3.27%	5.50%	8.86%	0.0032%
MONSANTO CO	MON	52,252.61	0.36%	1.53%	13.50%	15.13%	0.0539%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
MOSAIC CO/THE	MOS	22,866.87	0.16%	2.05%	12.50%	14.68%	0.0229%
MARATHON PETROLEUM CORP	MPC	23,128.71	0.16%	1.98%	0.00%	1.98%	0.0031%
MERCK & CO. INC.	MRK	140,458.80	0.96%	3.70%	2.00%	5.74%	0.0549%
MARATHON OIL CORP	MRO	24,900.36	0.17%	2.16%	0.00%	2.16%	0.0037%
MORGAN STANLEY	MS	47,132.39	0.32%	0.83%	21.50%	22.42%	0.0720%
MICROSOFT CORP	MSFT	283,949.50	1.94%	2.71%	10.50%	13.35%	0.2584%
MOTOROLA SOLUTIONS INC	MSI	15,555.08	0.11%	1.89%	15.50%	17.54%	0.0186%
M & T BANK CORP	MTB	14,647.84	0.10%	2.47%	7.00%	9.56%	0.0095%
MICRON TECHNOLOGY INC	MU	14,516.12	0.10%	0.00%	30.50%	30.50%	0.0302%
MURPHY OIL CORP	MUR	11,685.64	0.08%	2.04%	14.50%	16.69%	0.0133%
MEADWESTVACO CORP	MWV	6,045.69	0.04%	2.93%	9.00%	12.06%	0.0050%
MYLAN INC	MYL	11,609.77	0.08%	0.00%	12.00%	12.00%	0.0095%
NOBLE ENERGY INC	NBL	22,063.54	0.15%	0.91%	15.00%	15.98%	0.0240%
NABORS INDUSTRIES LTD	NBR	4,648.87	0.03%	1.01%	17.50%	18.60%	0.0059%
NASDAQ OMX GROUP/THE	NDAQ	5,423.70	0.04%	1.59%	7.00%	8.65%	0.0032%
NOBLE CORP	NE	9,535.20	0.06%	2.66%	19.50%	22.42%	0.0146%
NEXTERA ENERGY INC	NEE	34,021.99	0.23%	3.37%	5.00%	8.45%	0.0196%
NEWMONT MINING CORP	NEM	14,429.12	0.10%	2.07%	-13.50%	-11.57%	-0.0114%
NETFLIX INC	NFLX	12,402.55	0.08%	0.00%	16.00%	16.00%	0.0135%
NEWFIELD EXPLORATION CO	NFX	3,164.93	0.02%	0.00%	-0.50%	-0.50%	-0.0001%
NISOURCE INC	NI	8,924.12	0.06%	3.42%	8.50%	12.07%	0.0073%
NIKE INC -CL B	NKE	56,172.58	0.38%	1.34%	13.00%	14.43%	0.0552%
NORTHROP GRUMMAN CORP	NOC	19,497.01	0.13%	2.94%	2.00%	4.97%	0.0066%
NATIONAL OILWELL VARCO INC	NOV	30,042.13	0.20%	1.48%	11.50%	13.07%	0.0267%
NRG ENERGY INC	NRG	8,466.30	0.06%	1.83%	6.50%	8.39%	0.0048%
NORFOLK SOUTHERN CORP	NSC	22,579.21	0.15%	2.79%	9.50%	12.42%	0.0191%
NETAPP INC	NTAP	13,661.34	0.09%	1.57%	6.00%	7.62%	0.0071%
NORTHERN TRUST CORP	NTRS	14,074.43	0.10%	2.11%	8.00%	10.19%	0.0098%
NORTHEAST UTILITIES	NU	13,017.94	0.09%	3.60%	8.00%	11.74%	0.0104%
NUCOR CORP	NUE	13,839.45	0.09%	3.40%	26.00%	29.84%	0.0281%
NVIDIA CORP	NVDA	8,165.95	0.06%	2.12%	9.00%	11.22%	0.0062%
NEWELL RUBBERMAID INC	NWL	7,501.00	0.05%	2.31%	13.50%	15.97%	0.0082%
NEWS CORP - CLASS A	NWSA	N/A	N/A	N/A	N/A	N/A	N/A
NYSE EURONEXT	NYX	9,919.26	0.07%	2.94%	6.00%	9.03%	0.0061%
OWENS-ILLINOIS INC	OI	4,569.64	0.03%	0.00%	8.50%	8.50%	0.0026%
ONEOK INC	OKE	8,282.68	0.06%	3.98%	12.00%	16.22%	0.0092%
OMNICOM GROUP	OMC	16,156.27	0.11%	2.56%	11.50%	14.21%	0.0156%
ORACLE CORP	ORCL	144,873.30	0.99%	0.78%	10.00%	10.82%	0.1068%
O'REILLY AUTOMOTIVE INC	ORLY	12,720.86	0.09%	0.00%	13.50%	13.50%	0.0117%
OCCIDENTAL PETROLEUM CORP	OXY	72,314.51	0.49%	3.05%	7.00%	10.16%	0.0501%
PAYCHEX INC	PAYX	13,522.41	0.09%	3.63%	7.50%	11.27%	0.0104%
PEOPLE'S UNITED FINANCIAL	PBCT	4,806.54	0.03%	4.34%	17.50%	22.22%	0.0073%
PITNEY BOWES INC	PBI	2,860.87	0.02%	5.28%	-1.00%	4.25%	0.0008%
PACCAR INC	PCAR	18,912.34	0.13%	3.09%	20.00%	23.40%	0.0302%
P G & E CORP	PCG	19,516.98	0.13%	4.05%	4.00%	8.13%	0.0108%
PLUM CREEK TIMBER CO	PCL	7,547.65	0.05%	3.79%	10.50%	14.49%	0.0075%
PRICELINE COM INC	PCLN	42,320.73	0.29%	0.00%	20.50%	20.50%	0.0591%
PRECISION CASTPARTS CORP	PCP	33,655.16	0.23%	0.05%	12.50%	12.55%	0.0288%
PATTERSON COS INC	PDCO	3,854.39	0.03%	1.70%	10.00%	11.79%	0.0031%
PUBLIC SERVICE ENTERPRISE GP	PEG	16,086.47	0.11%	4.56%	-2.50%	2.00%	0.0022%
PEPSICO INC	PEP	124,727.80	0.85%	2.82%	8.50%	11.44%	0.0972%
PETSMART INC	PETM	7,053.95	0.05%	1.04%	16.00%	17.12%	0.0082%
PFIZER INC	PFE	196,127.60	1.34%	3.47%	12.00%	15.68%	0.2095%
PRINCIPAL FINANCIAL GROUP	PFG	10,843.30	0.07%	2.49%	7.50%	10.08%	0.0075%
PROCTER & GAMBLE CO/THE	PG	215,342.60	1.47%	3.07%	8.00%	11.19%	0.1643%
PROGRESSIVE CORP	PGR	15,350.68	0.10%	1.10%	15.50%	16.69%	0.0175%
PARKER HANNIFIN CORP	PH	14,226.61	0.10%	1.89%	11.00%	12.99%	0.0126%
PULTEGROUP INC	PHM	7,420.82	0.05%	0.00%	0.00%	0.00%	0.0000%
PERKINELMER INC	PKI	3,623.31	0.02%	0.86%	10.00%	10.90%	0.0027%
PROLOGIS INC	PLD	-	0.00%	3.15%	0.00%	3.15%	0.0000%
PALL CORP	PLL	7,473.16	0.05%	1.49%	9.00%	10.56%	0.0054%
PHILIP MORRIS INTERNATIONAL	PM	143,842.50	0.98%	3.95%	9.00%	13.13%	0.1287%
PNC FINANCIAL SERVICES GROUP	PNC	39,130.13	0.27%	2.38%	7.00%	9.46%	0.0252%
PENTAIR LTD-REGISTERED	PNR	11,847.96	0.08%	1.59%	17.50%	19.23%	0.0155%
PINNACLE WEST CAPITAL	PNW	6,024.00	0.04%	4.05%	5.00%	9.15%	0.0038%
PEPCO HOLDINGS INC	POM	4,841.77	0.03%	5.54%	6.00%	11.71%	0.0039%
PPG INDUSTRIES INC	PPG	21,338.41	0.15%	1.63%	9.00%	10.70%	0.0156%
PPL CORPORATION	PPL	17,257.30	0.12%	5.00%	0.00%	5.00%	0.0059%
PERRIGO CO	PRGO	11,482.91	0.08%	0.30%	13.50%	13.82%	0.0108%
PRUDENTIAL FINANCIAL INC	PRU	34,505.43	0.24%	2.37%	10.50%	12.99%	0.0306%
PUBLIC STORAGE	PSA	-	0.00%	3.35%	0.00%	3.35%	0.0000%
PHILLIPS 66	PSX	35,717.30	0.24%	2.31%	0.00%	2.31%	0.0056%
PVH CORP	PVH	10,212.77	0.07%	0.12%	13.50%	13.63%	0.0095%
QUANTA SERVICES INC	PWR	5,576.90	0.04%	0.00%	18.00%	18.00%	0.0068%
PRAXAIR INC	PX	33,943.23	0.23%	2.21%	11.00%	13.33%	0.0308%
PIONEER NATURAL RESOURCES CO	PXD	20,298.72	0.14%	0.05%	21.50%	21.56%	0.0298%
QUALCOMM INC	QCOM	105,130.70	0.72%	2.30%	11.50%	13.93%	0.0998%
QEP RESOURCES INC	QEP	5,126.95	0.03%	0.32%	11.00%	11.34%	0.0040%
RYDER SYSTEM INC	R	3,105.46	0.02%	2.07%	14.50%	16.72%	0.0035%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
REYNOLDS AMERICAN INC	RAI	26,589.16	0.18%	5.19%	9.50%	14.94%	0.0271%
ROWAN COMPANIES PLC-A	RDC	4,235.37	0.03%	0.00%	20.50%	20.50%	0.0059%
REGENERON PHARMACEUTICALS	REGN	22,759.12	0.16%	0.00%	0.00%	0.00%	0.0000%
REGIONS FINANCIAL CORP	RF	13,960.44	0.10%	1.22%	72.50%	74.16%	0.0706%
ROBERT HALF INTL INC	RHI	4,333.54	0.03%	2.09%	19.50%	21.79%	0.0064%
RED HAT INC	RHT	9,236.06	0.06%	0.00%	15.00%	15.00%	0.0094%
RALPH LAUREN CORP	RL	15,706.61	0.11%	0.93%	11.00%	11.98%	0.0128%
ROCKWELL AUTOMATION INC	ROK	11,841.69	0.08%	2.45%	7.50%	10.04%	0.0081%
ROPER INDUSTRIES INC	ROP	12,332.69	0.08%	0.53%	14.50%	15.07%	0.0127%
ROSS STORES INC	ROST	14,299.29	0.10%	1.04%	13.50%	14.61%	0.0142%
RANGE RESOURCES CORP	RRC	12,388.85	0.08%	0.21%	34.00%	34.25%	0.0289%
REPUBLIC SERVICES INC	RSG	12,182.79	0.08%	2.94%	10.00%	13.09%	0.0109%
RAYTHEON COMPANY	RTN	21,134.66	0.14%	3.38%	4.50%	7.96%	0.0115%
SPRINT NEXTEL CORP	S	21,663.47	0.15%	0.00%	0.00%	0.00%	0.0000%
SAIC INC	SAI	4,733.28	0.03%	3.47%	5.50%	9.07%	0.0029%
STARBUCKS CORP	SBUX	50,360.59	0.34%	1.34%	19.50%	20.97%	0.0720%
SCANA CORP	SCG	6,759.55	0.05%	4.20%	4.50%	8.79%	0.0041%
SCHWAB (CHARLES) CORP	SCHW	27,388.54	0.19%	1.12%	11.50%	12.68%	0.0237%
SPECTRA ENERGY CORP	SE	23,100.64	0.16%	3.59%	4.50%	8.17%	0.0129%
SEALED AIR CORP	SEE	4,887.77	0.03%	2.08%	15.50%	17.74%	0.0059%
SHERWIN-WILLIAMS CO/THE	SHW	18,336.67	0.12%	1.20%	15.50%	16.79%	0.0210%
SIGMA-ALDRICH	SIAL	9,735.02	0.07%	1.06%	8.50%	9.61%	0.0064%
JM SMUCKER CO/THE	SJM	11,129.17	0.08%	2.03%	8.50%	10.62%	0.0081%
SCHLUMBERGER LTD	SLB	97,063.14	0.66%	1.71%	15.00%	16.84%	0.1114%
SLM CORP	SLM	10,369.17	0.07%	2.62%	8.50%	11.23%	0.0079%
SNAP-ON INC	SNA	5,280.16	0.04%	1.68%	11.00%	12.77%	0.0046%
SANDISK CORP	SNDK	14,945.23	0.10%	0.00%	8.50%	8.50%	0.0087%
SCRIPPS NETWORKS INTER-CL A	SNI	10,104.63	0.07%	0.87%	9.00%	9.91%	0.0068%
SOUTHERN CO/THE	SO	37,774.93	0.26%	4.72%	4.50%	9.33%	0.0240%
SIMON PROPERTY GROUP INC	SPG	-	0.00%	3.08%	0.00%	3.08%	0.0000%
STAPLES INC	SPLS	10,573.83	0.07%	3.02%	9.50%	12.66%	0.0091%
STERICYCLE INC	SRCL	9,576.23	0.07%	0.00%	12.00%	12.00%	0.0078%
SEMPRA ENERGY	SRE	19,543.81	0.13%	3.17%	4.50%	7.74%	0.0103%
SUNTRUST BANKS INC	STI	17,634.59	0.12%	1.22%	26.00%	27.38%	0.0329%
ST JUDE MEDICAL INC	STJ	12,912.14	0.09%	2.19%	10.00%	12.30%	0.0108%
STATE STREET CORP	STT	29,982.51	0.20%	1.61%	9.00%	10.68%	0.0218%
SEAGATE TECHNOLOGY	STX	16,158.56	0.11%	3.37%	10.00%	13.54%	0.0149%
CONSTELLATION BRANDS INC-A	STZ	9,576.40	0.07%	0.00%	12.00%	12.00%	0.0078%
STANLEY BLACK & DECKER INC	SWK	12,614.88	0.09%	2.52%	11.50%	14.16%	0.0122%
SOUTHWESTERN ENERGY CO	SWN	13,186.27	0.09%	0.00%	10.50%	10.50%	0.0094%
SAFEWAY INC	SWY	5,597.89	0.04%	3.39%	8.50%	12.03%	0.0046%
STRYKER CORP	SYK	24,271.19	0.17%	1.65%	7.00%	8.71%	0.0144%
SYMANTEC CORP	SYMC	15,410.24	0.11%	2.68%	13.50%	16.36%	0.0172%
SYSCO CORP	SYY	20,022.15	0.14%	3.32%	7.50%	10.94%	0.0149%
AT&T INC	T	193,160.40	1.32%	5.11%	7.00%	12.29%	0.1618%
MOLSON COORS BREWING CO -B	TAP	8,671.30	0.06%	2.69%	7.00%	9.78%	0.0058%
TERADATA CORP	TDC	8,453.66	0.06%	0.00%	14.00%	14.00%	0.0081%
TECO ENERGY INC	TE	3,634.43	0.02%	5.27%	3.50%	8.86%	0.0022%
INTEGRYS ENERGY GROUP INC	TEG	4,515.48	0.03%	4.72%	3.50%	8.30%	0.0026%
TE CONNECTIVITY LTD	TEL	19,284.50	0.13%	2.16%	8.00%	10.25%	0.0135%
TERADYNE INC	TER	3,286.68	0.02%	0.00%	5.00%	5.00%	0.0011%
TARGET CORP	TGT	44,490.14	0.30%	2.48%	11.50%	14.12%	0.0428%
TENET HEALTHCARE CORP	THC	4,513.51	0.03%	0.00%	28.50%	28.50%	0.0088%
TIFFANY & CO	TIF	9,257.13	0.06%	1.93%	11.50%	13.54%	0.0085%
TJX COMPANIES INC	TJX	36,197.39	0.25%	1.15%	13.50%	14.73%	0.0363%
TORCHMARK CORP	TMK	6,114.49	0.04%	1.03%	7.50%	8.57%	0.0036%
THERMO FISHER SCIENTIFIC INC	TMO	30,490.34	0.21%	0.71%	11.50%	12.25%	0.0255%
TRIPADVISOR INC	TRIP	8,713.88	0.06%	0.00%	0.00%	0.00%	0.0000%
T ROWE PRICE GROUP INC	TROW	19,200.57	0.13%	2.09%	12.50%	14.72%	0.0193%
TRAVELERS COS INC/THE	TRV	30,262.56	0.21%	2.49%	9.50%	12.11%	0.0250%
TYSON FOODS INC-CL A	TSN	9,236.54	0.06%	0.77%	9.00%	9.80%	0.0062%
TESORO CORP	TSO	6,902.06	0.05%	1.59%	18.00%	19.73%	0.0093%
TOTAL SYSTEM SERVICES INC	TSS	4,634.48	0.03%	1.62%	9.00%	10.69%	0.0034%
TIME WARNER CABLE	TWC	32,925.36	0.22%	2.31%	11.50%	13.94%	0.0313%
TIME WARNER INC	TWX	56,045.31	0.38%	1.91%	11.00%	13.02%	0.0497%
TEXAS INSTRUMENTS INC	TXN	39,341.70	0.27%	3.16%	4.00%	7.22%	0.0194%
TEXTRON INC	TXT	7,078.72	0.05%	0.31%	18.00%	18.34%	0.0088%
TYCO INTERNATIONAL LTD	TYC	15,816.08	0.11%	1.87%	0.00%	1.87%	0.0020%
UNITEDHEALTH GROUP INC	UNH	66,392.02	0.45%	1.71%	10.00%	11.80%	0.0534%
UNUM GROUP	UNM	7,920.91	0.05%	1.96%	6.50%	8.52%	0.0046%
UNION PACIFIC CORP	UNP	72,546.37	0.49%	1.78%	12.00%	13.89%	0.0687%
UNITED PARCEL SERVICE-CL B	UPS	81,507.36	0.56%	2.88%	7.50%	10.49%	0.0583%
URBAN OUTFITTERS INC	URBN	5,926.84	0.04%	0.00%	14.00%	14.00%	0.0057%
US BANCORP	USB	67,538.30	0.46%	2.53%	9.00%	11.64%	0.0536%
UNITED TECHNOLOGIES CORP	UTX	87,085.28	0.59%	2.26%	10.00%	12.37%	0.0734%
VISA INC-CLASS A SHARES	V	148,322.70	1.01%	0.73%	18.00%	18.80%	0.1900%
VARIAN MEDICAL SYSTEMS INC	VAR	7,202.61	0.05%	0.00%	9.50%	9.50%	0.0047%
VF CORP	VFC	21,176.19	0.14%	1.80%	12.00%	13.91%	0.0201%
VIACOM INC-CLASS B	VIAB	33,309.75	0.23%	1.75%	13.50%	15.37%	0.0349%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
VALERO ENERGY CORP	VLO	18,463.20	0.13%	2.38%	17.00%	19.58%	0.0246%
VULCAN MATERIALS CO	VMC	6,167.47	0.04%	0.08%	0.00%	0.08%	0.0000%
VORNADO REALTY TRUST	VNO	15,730.58	0.11%	3.47%	7.00%	10.59%	0.0114%
VERISIGN INC	VRSN	6,803.33	0.05%	0.00%	19.00%	19.00%	0.0088%
VENTAS INC	VTR	-	0.00%	3.87%	0.00%	3.87%	0.0000%
VERIZON COMMUNICATIONS INC	VZ	145,945.60	0.99%	4.04%	8.00%	12.20%	0.1214%
WALGREEN CO	WAG	41,693.54	0.28%	2.49%	9.50%	12.11%	0.0344%
WATERS CORP	WAT	8,606.16	0.06%	0.00%	9.50%	9.50%	0.0056%
WESTERN DIGITAL CORP	WDC	15,043.98	0.10%	1.58%	7.50%	9.14%	0.0094%
WISCONSIN ENERGY CORP	WEC	9,217.54	0.06%	3.57%	5.50%	9.17%	0.0058%
WELLS FARGO & CO	WFC	218,003.20	1.49%	2.94%	8.00%	11.06%	0.1643%
WHOLE FOODS MARKET INC	WFM	19,642.31	0.13%	0.81%	18.00%	18.88%	0.0253%
WHIRLPOOL CORP	WHR	9,084.21	0.06%	2.17%	9.50%	11.77%	0.0073%
WINDSTREAM CORP	WIN	4,658.62	0.03%	12.72%	11.50%	24.95%	0.0079%
WELLPOINT INC	WLP	24,383.19	0.17%	1.85%	5.50%	7.40%	0.0123%
WASTE MANAGEMENT INC	WM	18,743.97	0.13%	3.63%	6.50%	10.25%	0.0131%
WILLIAMS COS INC	WMB	22,383.24	0.15%	4.57%	7.00%	11.73%	0.0179%
WAL-MART STORES INC	WMT	245,736.10	1.67%	2.52%	9.00%	11.63%	0.1948%
WASHINGTON POST-CLASS B	WPO	3,670.85	0.03%	1.98%	5.00%	7.03%	0.0018%
WPX ENERGY INC	WPX	3,779.66	0.03%	0.00%	0.00%	0.00%	0.0000%
WESTERN UNION CO	WU	9,465.05	0.06%	2.96%	6.00%	9.05%	0.0058%
WEYERHAEUSER CO	WY	15,555.44	0.11%	2.81%	21.50%	24.61%	0.0261%
WYNDHAM WORLDWIDE CORP	WYN	7,728.88	0.05%	2.04%	13.00%	15.17%	0.0080%
WYNN RESORTS LTD	WYNN	12,728.79	0.09%	3.17%	14.00%	17.39%	0.0151%
UNITED STATES STEEL CORP	X	2,623.08	0.02%	1.10%	0.00%	1.10%	0.0002%
XCEL ENERGY INC	XEL	13,981.78	0.10%	3.96%	4.50%	8.55%	0.0081%
XL GROUP PLC	XL	9,035.13	0.06%	1.85%	17.00%	19.01%	0.0117%
XILINX INC	XLNX	10,421.88	0.07%	2.51%	7.00%	9.60%	0.0068%
EXXON MOBIL CORP	XOM	403,241.80	2.75%	2.78%	6.50%	9.37%	0.2575%
DENTSPLY INTERNATIONAL INC	XRAY	5,887.13	0.04%	0.61%	9.00%	9.64%	0.0039%
XEROX CORP	XRX	11,394.93	0.08%	2.80%	8.50%	11.42%	0.0089%
XYLEM INC	XYL	5,119.84	0.03%	1.70%	0.00%	1.70%	0.0006%
YAHOO! INC	YHOO	27,759.16	0.19%	0.00%	10.00%	10.00%	0.0189%
YUM! BRANDS INC	YUM	32,004.00	0.22%	2.01%	9.50%	11.61%	0.0253%
ZIONS BANCORPORATION	ZION	5,468.87	0.04%	0.54%	0.00%	0.54%	0.0002%
ZIMMER HOLDINGS INC	ZMH	12,640.39	0.09%	1.09%	10.00%	11.14%	0.0096%
ZOETIS INC	ZTS	N/A	N/A	N/A	N/A	N/A	N/A
Total Market Capitalization:		14,674,009.84					12.72%

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] - [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Bloomberg and Value Line Beta Coefficients

Hevert Proxy Group	Ticker	[1] Bloomberg	[2] Value Line
American Electric Power Company, Inc.	AEP	0.619	0.65
Cleco Corp.	CNL	0.767	0.65
Empire District Electric	EDE	0.751	0.65
Great Plains Energy Inc.	GXP	0.779	0.80
IDACORP, Inc.	IDA	0.828	0.70
Otter Tail Corporation	OTTR	0.771	0.90
Pinnacle West Capital Corp.	PNW	0.729	0.70
PNM Resources, Inc.	PNM	0.668	0.95
Portland General Electric Company	POR	0.765	0.75
Southern Company	SO	0.507	0.55
Westar Energy, Inc.	WR	0.672	0.75
Mean		0.714	0.73
Median		0.751	0.70

Combined Proxy Group	Ticker	Bloomberg	Value Line
American Electric Power Company, Inc.	AEP	0.619	0.65
Black Hills Corporation	BKH	0.823	0.80
Cleco Corporation	CNL	0.767	0.65
CMS Energy Corporation	CMS	0.712	0.75
Consolidated Edison, Inc.	ED	0.504	0.60
Dominion Resources, Inc.	D	0.553	0.65
Empire District Electric Company	EDE	0.751	0.65
Great Plains Energy Inc.	GXP	0.779	0.80
Hawaiian Electric Industries, Inc.	HE	0.713	0.70
IDACORP, Inc.	IDA	0.828	0.70
Otter Tail Corporation	OTTR	0.771	0.90
Pepco Holdings, Inc.	POM	0.653	0.75
Pinnacle West Capital Corporation	PNW	0.729	0.70
PNM Resources, Inc.	PNM	0.668	0.95
Portland General Electric Company	POR	0.765	0.75
SCANA Corporation	SCG	0.634	0.65
Southern Company	SO	0.507	0.55
UIL Holdings Corporation	UIL	0.691	0.70
UniSource Energy Corporation	UNS	0.700	0.70
Westar Energy, Inc.	WR	0.672	0.75
Wisconsin Energy Corporation	WEC	0.598	0.60
Mean		0.688	0.71
Median		0.700	0.70

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

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WITNESS: HEVERT
DOCUMENT NO. 5
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Capital Asset Pricing Model Results
Bloomberg and Value Line Derived Market Risk Premium

	[1]	[2]	[3]	[4]	[5]	[6]
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
MR. HEVERT'S PROXY GROUP AVERAGE BLOOMBERG BETA COEFFICIENT						
Current 30-Year Treasury (30-day average) [7]	3.46%	0.714	9.98%	9.27%	10.59%	10.07%
Near-Term Projected 30-Year Treasury [8]	3.73%	0.714	9.98%	9.27%	10.86%	10.35%
Long-Term Projected 30-Year Treasury [9]	5.40%	0.714	9.98%	9.27%	12.53%	12.02%
Mean					11.33%	10.82%

	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
MR. HEVERT'S PROXY GROUP AVERAGE VALUE LINE BETA COEFFICIENT						
Current 30-Year Treasury (30-day average) [7]	3.46%	0.732	9.98%	9.27%	10.76%	10.24%
Near-Term Projected 30-Year Treasury [8]	3.73%	0.732	9.98%	9.27%	11.04%	10.52%
Long-Term Projected 30-Year Treasury [9]	5.40%	0.732	9.98%	9.27%	12.71%	12.18%
Mean					11.50%	10.98%

	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
COMBINED PROXY GROUP AVERAGE BLOOMBERG BETA COEFFICIENT						
Current 30-Year Treasury (30-day average) [7]	3.46%	0.688	9.98%	9.27%	10.32%	9.83%
Near-Term Projected 30-Year Treasury [8]	3.73%	0.688	9.98%	9.27%	10.60%	10.11%
Long-Term Projected 30-Year Treasury [9]	5.40%	0.688	9.98%	9.27%	12.26%	11.77%
Mean					11.06%	10.57%

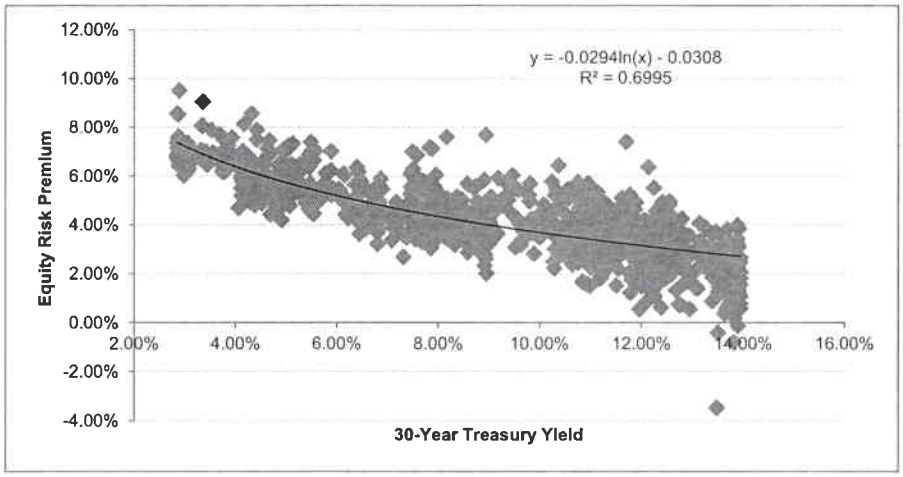
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
COMBINED PROXY GROUP AVERAGE VALUE LINE BETA COEFFICIENT						
Current 30-Year Treasury (30-day average) [7]	3.46%	0.712	9.98%	9.27%	10.56%	10.05%
Near-Term Projected 30-Year Treasury [8]	3.73%	0.712	9.98%	9.27%	10.84%	10.33%
Long-Term Projected 30-Year Treasury [9]	5.40%	0.712	9.98%	9.27%	12.51%	12.00%
Mean					11.30%	10.79%

Notes:
[1] See *Notes [7], [8] and [9]*
[2] Source: Document No. 4
[3] Source: Document No. 3
[4] Source: Document No. 3
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Source: Bloomberg Professional
[8] Source: Blue Chip Financial Forecasts, Vol. 32, No. 7, July 1, 2013, at 2
[9] Source: Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, 2013, at 14

Bond Yield Plus Risk Premium Analysis

	[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
Current	-3.08%	-2.94%	3.46%	6.81%	10.27%
Near Term Projected	-3.08%	-2.94%	3.73%	6.58%	10.32%
Long Term Projected	-3.08%	-2.94%	5.40%	5.50%	10.90%

Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 32, No. 7, July 1, 2013, at 2,
Long-Term Projected = Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, 2013, at 14
[4] Equals [1] + [2] x ln([3])
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional, equals 201-trading day average (i.e. lag period)
[9] Equals [7] - [8]



[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.38%	5.01%
1/9/1980	15.00%	9.39%	5.61%
1/14/1980	15.17%	9.41%	5.76%
1/17/1980	13.93%	9.43%	4.50%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.63%	3.17%
2/14/1980	13.00%	9.64%	3.36%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.89%	2.81%
3/14/1980	13.50%	9.96%	3.54%
3/26/1980	14.16%	10.09%	4.07%
3/27/1980	14.24%	10.11%	4.13%
3/28/1980	14.50%	10.13%	4.37%
4/11/1980	12.75%	10.27%	2.48%
4/14/1980	13.85%	10.28%	3.57%
4/16/1980	15.50%	10.30%	5.20%
4/22/1980	13.25%	10.34%	2.91%
4/22/1980	13.90%	10.34%	3.56%
4/24/1980	16.80%	10.37%	6.43%
4/29/1980	15.50%	10.40%	5.10%
5/6/1980	13.70%	10.44%	3.26%
5/7/1980	15.00%	10.45%	4.55%
5/8/1980	13.75%	10.45%	3.30%
5/9/1980	14.35%	10.46%	3.89%
5/13/1980	13.60%	10.47%	3.13%
5/15/1980	13.25%	10.49%	2.76%
5/19/1980	13.75%	10.50%	3.25%
5/27/1980	13.62%	10.53%	3.09%
5/27/1980	14.60%	10.53%	4.07%
5/29/1980	16.00%	10.55%	5.45%
5/30/1980	13.80%	10.56%	3.24%
6/2/1980	15.63%	10.56%	5.07%
6/9/1980	15.90%	10.59%	5.31%
6/10/1980	13.78%	10.59%	3.19%
6/12/1980	14.25%	10.60%	3.65%
6/19/1980	13.40%	10.61%	2.79%
6/30/1980	13.00%	10.64%	2.36%
6/30/1980	13.40%	10.64%	2.76%
7/9/1980	14.75%	10.67%	4.08%
7/10/1980	15.00%	10.67%	4.33%
7/15/1980	15.80%	10.69%	5.11%
7/18/1980	13.80%	10.70%	3.10%
7/22/1980	14.10%	10.71%	3.39%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
7/24/1980	15.00%	10.72%	4.28%
7/25/1980	13.48%	10.73%	2.75%
7/31/1980	14.58%	10.75%	3.83%
8/8/1980	13.50%	10.77%	2.73%
8/8/1980	14.00%	10.77%	3.23%
8/8/1980	15.45%	10.77%	4.68%
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.83%	1.67%
9/15/1980	13.50%	10.87%	2.63%
9/15/1980	13.93%	10.87%	3.06%
9/15/1980	15.80%	10.87%	4.93%
9/24/1980	12.50%	10.92%	1.58%
9/24/1980	15.00%	10.92%	4.08%
9/26/1980	13.75%	10.94%	2.81%
9/30/1980	14.10%	10.96%	3.14%
9/30/1980	14.20%	10.96%	3.24%
10/1/1980	13.90%	10.96%	2.94%
10/3/1980	15.50%	10.98%	4.52%
10/7/1980	12.50%	10.99%	1.51%
10/9/1980	13.25%	11.00%	2.25%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	14.50%	11.00%	3.50%
10/16/1980	16.10%	11.02%	5.08%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	13.75%	11.10%	2.65%
10/31/1980	14.25%	11.10%	3.15%
11/4/1980	15.00%	11.11%	3.89%
11/5/1980	13.75%	11.12%	2.63%
11/5/1980	14.00%	11.12%	2.88%
11/8/1980	13.75%	11.14%	2.61%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.21%	2.79%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	14.15%	11.23%	2.92%
12/8/1980	15.10%	11.23%	3.87%
12/9/1980	15.35%	11.23%	4.12%
12/12/1980	15.45%	11.23%	4.22%
12/17/1980	13.25%	11.24%	2.01%
12/18/1980	15.80%	11.24%	4.56%
12/19/1980	14.50%	11.24%	3.26%
12/19/1980	14.64%	11.24%	3.40%
12/22/1980	13.45%	11.24%	2.21%
12/22/1980	15.00%	11.24%	3.76%
12/30/1980	14.50%	11.22%	3.28%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
12/30/1980	14.95%	11.22%	3.73%
12/31/1980	13.39%	11.22%	2.17%
1/2/1981	15.25%	11.22%	4.03%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.20%	4.05%
1/23/1981	13.10%	11.20%	1.90%
1/23/1981	14.40%	11.20%	3.20%
1/26/1981	15.25%	11.21%	4.04%
1/27/1981	15.00%	11.21%	3.79%
1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.24%	4.51%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.33%	3.92%
3/11/1981	15.40%	11.49%	3.91%
3/12/1981	14.51%	11.50%	3.01%
3/12/1981	16.00%	11.50%	4.50%
3/13/1981	13.02%	11.51%	1.51%
3/18/1981	16.19%	11.54%	4.65%
3/19/1981	13.75%	11.55%	2.20%
3/23/1981	14.30%	11.57%	2.73%
3/25/1981	15.30%	11.60%	3.70%
4/1/1981	14.53%	11.67%	2.86%
4/3/1981	19.10%	11.70%	7.40%
4/9/1981	15.00%	11.77%	3.23%
4/9/1981	15.30%	11.77%	3.53%
4/9/1981	16.50%	11.77%	4.73%
4/9/1981	17.00%	11.77%	5.23%
4/10/1981	13.75%	11.79%	1.96%
4/13/1981	13.57%	11.81%	1.76%
4/15/1981	15.30%	11.84%	3.46%
4/16/1981	13.50%	11.86%	1.64%
4/17/1981	14.10%	11.86%	2.24%
4/21/1981	14.00%	11.89%	2.11%
4/21/1981	16.80%	11.89%	4.91%
4/24/1981	16.00%	11.94%	4.06%
4/27/1981	12.50%	11.96%	0.54%
4/27/1981	13.61%	11.96%	1.65%
4/29/1981	13.65%	11.99%	1.66%
4/30/1981	13.50%	12.01%	1.49%
5/4/1981	16.22%	12.04%	4.18%
5/5/1981	14.40%	12.06%	2.34%
5/7/1981	16.25%	12.10%	4.15%
5/7/1981	16.27%	12.10%	4.17%
5/8/1981	13.00%	12.12%	0.88%
5/8/1981	16.00%	12.12%	3.88%
5/12/1981	13.50%	12.15%	1.35%
5/15/1981	15.75%	12.21%	3.54%
5/18/1981	14.88%	12.22%	2.66%
5/20/1981	16.00%	12.25%	3.75%
5/21/1981	14.00%	12.27%	1.73%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
5/26/1981	14.90%	12.29%	2.61%
5/27/1981	15.00%	12.31%	2.69%
5/27/1981	15.00%	12.31%	2.69%
5/29/1981	15.50%	12.33%	3.17%
6/1/1981	16.50%	12.34%	4.16%
6/3/1981	14.67%	12.36%	2.31%
6/5/1981	13.00%	12.38%	0.62%
6/10/1981	16.75%	12.41%	4.34%
6/17/1981	14.40%	12.45%	1.95%
6/18/1981	16.33%	12.46%	3.87%
6/25/1981	14.75%	12.51%	2.24%
6/26/1981	16.00%	12.52%	3.48%
6/30/1981	15.25%	12.54%	2.71%
7/1/1981	15.50%	12.55%	2.95%
7/1/1981	17.50%	12.55%	4.95%
7/10/1981	16.00%	12.61%	3.39%
7/14/1981	16.90%	12.63%	4.27%
7/15/1981	16.00%	12.64%	3.36%
7/17/1981	15.00%	12.66%	2.34%
7/20/1981	15.00%	12.67%	2.33%
7/21/1981	14.00%	12.68%	1.32%
7/28/1981	13.48%	12.73%	0.75%
7/31/1981	13.50%	12.77%	0.73%
7/31/1981	15.00%	12.77%	2.23%
7/31/1981	16.00%	12.77%	3.23%
8/5/1981	15.71%	12.82%	2.89%
8/10/1981	14.50%	12.86%	1.64%
8/11/1981	15.00%	12.87%	2.13%
8/20/1981	13.50%	12.94%	0.56%
8/20/1981	16.50%	12.94%	3.56%
8/24/1981	15.00%	12.96%	2.04%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.05%	1.45%
9/10/1981	14.50%	13.10%	1.40%
9/11/1981	16.00%	13.11%	2.89%
9/16/1981	16.00%	13.14%	2.86%
9/17/1981	16.50%	13.15%	3.35%
9/23/1981	15.85%	13.19%	2.66%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.32%	2.43%
10/15/1981	16.25%	13.36%	2.89%
10/16/1981	15.50%	13.37%	2.13%
10/16/1981	16.50%	13.37%	3.13%
10/19/1981	14.25%	13.38%	0.87%
10/20/1981	15.25%	13.40%	1.85%
10/20/1981	17.00%	13.40%	3.60%
10/23/1981	16.00%	13.44%	2.56%
10/27/1981	10.00%	13.48%	-3.48%
10/29/1981	14.75%	13.50%	1.25%
10/29/1981	16.50%	13.50%	3.00%
11/3/1981	15.17%	13.53%	1.64%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
11/5/1981	16.60%	13.55%	3.05%
11/6/1981	15.17%	13.55%	1.62%
11/24/1981	15.50%	13.60%	1.90%
11/25/1981	15.25%	13.60%	1.65%
11/25/1981	15.35%	13.60%	1.75%
11/25/1981	16.10%	13.60%	2.50%
11/25/1981	16.10%	13.60%	2.50%
12/1/1981	15.70%	13.61%	2.09%
12/1/1981	16.00%	13.61%	2.39%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	16.50%	13.61%	2.89%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.62%	2.63%
12/14/1981	14.00%	13.62%	0.38%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.63%	2.87%
12/18/1981	15.45%	13.63%	1.82%
12/30/1981	14.25%	13.66%	0.59%
12/30/1981	16.00%	13.66%	2.34%
12/30/1981	16.25%	13.66%	2.59%
12/31/1981	16.15%	13.67%	2.48%
1/4/1982	15.50%	13.67%	1.83%
1/11/1982	14.50%	13.72%	0.78%
1/11/1982	17.00%	13.72%	3.28%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.74%	2.01%
1/15/1982	15.00%	13.75%	1.25%
1/15/1982	16.50%	13.75%	2.75%
1/22/1982	16.25%	13.79%	2.46%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.81%	-0.81%
1/29/1982	15.50%	13.81%	1.69%
2/1/1982	15.85%	13.82%	2.03%
2/3/1982	16.44%	13.83%	2.61%
2/8/1982	15.50%	13.85%	1.65%
2/11/1982	16.00%	13.87%	2.13%
2/11/1982	16.20%	13.87%	2.33%
2/17/1982	15.00%	13.88%	1.12%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.88%	1.22%
3/27/1982	15.40%	13.89%	1.51%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
3/30/1982	15.50%	13.90%	1.60%
3/31/1982	17.00%	13.90%	3.10%
4/1/1982	14.70%	13.91%	0.79%
4/1/1982	16.50%	13.91%	2.59%
4/2/1982	15.50%	13.91%	1.59%
4/5/1982	15.50%	13.91%	1.59%
4/8/1982	16.40%	13.93%	2.47%
4/13/1982	14.50%	13.93%	0.57%
4/23/1982	15.75%	13.94%	1.81%
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	14.70%	13.94%	0.76%
4/30/1982	15.50%	13.94%	1.56%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.91%	0.78%
5/20/1982	15.00%	13.91%	1.09%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.88%	0.97%
6/18/1982	15.50%	13.87%	1.63%
6/21/1982	14.90%	13.87%	1.03%
6/23/1982	16.00%	13.87%	2.13%
6/23/1982	16.17%	13.87%	2.30%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.86%	0.84%
7/1/1982	16.00%	13.85%	2.15%
7/2/1982	15.62%	13.84%	1.78%
7/2/1982	17.00%	13.84%	3.16%
7/13/1982	14.00%	13.82%	0.18%
7/13/1982	16.80%	13.82%	2.98%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/19/1982	16.50%	13.80%	2.70%
7/22/1982	14.50%	13.78%	0.72%
7/22/1982	17.00%	13.78%	3.22%
7/27/1982	16.75%	13.75%	3.00%
7/29/1982	16.50%	13.74%	2.76%
8/11/1982	17.50%	13.69%	3.81%
8/18/1982	17.07%	13.64%	3.43%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
8/20/1982	15.73%	13.61%	2.12%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	13.08%	13.50%	-0.42%
9/15/1982	16.25%	13.50%	2.75%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.49%	1.76%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.46%	1.04%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.25%	2.50%
10/22/1982	17.15%	13.25%	3.90%
10/29/1982	15.54%	13.17%	2.37%
11/1/1982	15.50%	13.15%	2.35%
11/3/1982	17.20%	13.13%	4.07%
11/4/1982	16.25%	13.12%	3.13%
11/5/1982	16.20%	13.10%	3.10%
11/9/1982	16.00%	13.06%	2.94%
11/23/1982	15.50%	12.89%	2.61%
11/23/1982	15.85%	12.89%	2.96%
11/30/1982	16.50%	12.82%	3.68%
12/1/1982	17.04%	12.79%	4.25%
12/6/1982	15.00%	12.74%	2.26%
12/6/1982	16.35%	12.74%	3.61%
12/10/1982	15.50%	12.67%	2.83%
12/13/1982	16.00%	12.65%	3.35%
12/14/1982	15.30%	12.63%	2.67%
12/14/1982	16.40%	12.63%	3.77%
12/20/1982	16.00%	12.58%	3.42%
12/21/1982	14.75%	12.56%	2.19%
12/21/1982	15.85%	12.56%	3.29%
12/22/1982	16.25%	12.55%	3.70%
12/22/1982	16.58%	12.55%	4.03%
12/22/1982	16.75%	12.55%	4.20%
12/29/1982	14.90%	12.49%	2.41%
12/29/1982	16.25%	12.49%	3.76%
12/30/1982	16.00%	12.47%	3.53%
12/30/1982	16.35%	12.47%	3.88%
12/30/1982	16.77%	12.47%	4.30%
1/5/1983	17.33%	12.41%	4.92%
1/11/1983	15.90%	12.35%	3.55%
1/12/1983	14.63%	12.34%	2.29%
1/12/1983	15.50%	12.34%	3.16%
1/20/1983	17.75%	12.24%	5.51%
1/21/1983	15.00%	12.23%	2.77%
1/24/1983	14.50%	12.21%	2.29%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
1/24/1983	15.50%	12.21%	3.29%
1/25/1983	15.85%	12.20%	3.65%
1/27/1983	16.14%	12.17%	3.97%
2/1/1983	18.50%	12.14%	6.36%
2/4/1983	14.00%	12.10%	1.90%
2/10/1983	15.00%	12.06%	2.94%
2/21/1983	15.50%	11.99%	3.51%
2/22/1983	15.50%	11.98%	3.52%
2/23/1983	15.10%	11.96%	3.14%
2/23/1983	16.00%	11.96%	4.04%
3/2/1983	15.25%	11.90%	3.35%
3/9/1983	15.20%	11.83%	3.37%
3/15/1983	13.00%	11.78%	1.22%
3/18/1983	15.25%	11.74%	3.51%
3/23/1983	15.40%	11.70%	3.70%
3/24/1983	15.00%	11.68%	3.32%
3/29/1983	15.50%	11.64%	3.86%
3/30/1983	16.71%	11.62%	5.09%
3/31/1983	15.00%	11.61%	3.39%
4/4/1983	15.20%	11.59%	3.61%
4/8/1983	15.50%	11.52%	3.98%
4/11/1983	14.81%	11.50%	3.31%
4/19/1983	14.50%	11.39%	3.11%
4/20/1983	16.00%	11.37%	4.63%
4/29/1983	16.00%	11.26%	4.74%
5/1/1983	14.50%	11.26%	3.24%
5/9/1983	15.50%	11.16%	4.34%
5/11/1983	16.46%	11.13%	5.33%
5/12/1983	14.14%	11.12%	3.02%
5/18/1983	15.00%	11.06%	3.94%
5/23/1983	14.90%	11.02%	3.88%
5/23/1983	15.50%	11.02%	4.48%
5/25/1983	15.50%	11.00%	4.50%
5/27/1983	15.00%	10.97%	4.03%
5/31/1983	14.00%	10.96%	3.04%
5/31/1983	15.50%	10.96%	4.54%
6/2/1983	14.50%	10.94%	3.56%
6/17/1983	15.03%	10.85%	4.18%
7/1/1983	14.80%	10.78%	4.02%
7/1/1983	14.90%	10.78%	4.12%
7/8/1983	16.25%	10.76%	5.49%
7/13/1983	13.20%	10.76%	2.44%
7/19/1983	15.00%	10.75%	4.25%
7/19/1983	15.10%	10.75%	4.35%
7/25/1983	16.25%	10.74%	5.51%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.34%	10.75%	5.59%
8/3/1983	16.50%	10.75%	5.75%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	15.50%	10.80%	4.70%
8/22/1983	16.40%	10.80%	5.60%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
8/31/1983	14.75%	10.84%	3.91%
9/7/1983	15.00%	10.86%	4.14%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.94%	4.56%
9/30/1983	15.25%	10.95%	4.30%
9/30/1983	16.15%	10.95%	5.20%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.98%	4.54%
10/17/1983	15.50%	10.99%	4.51%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.25%	11.00%	5.25%
10/19/1983	16.50%	11.00%	5.50%
10/26/1983	15.00%	11.03%	3.97%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%
11/23/1983	16.00%	11.13%	4.87%
11/23/1983	16.15%	11.13%	5.02%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.15%	3.92%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.17%	3.33%
12/15/1983	15.56%	11.19%	4.37%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	14.69%	11.21%	3.48%
12/20/1983	16.00%	11.21%	4.79%
12/20/1983	16.25%	11.21%	5.04%
12/22/1983	14.75%	11.23%	3.52%
12/22/1983	15.75%	11.23%	4.52%
1/3/1984	14.75%	11.26%	3.49%
1/10/1984	15.90%	11.29%	4.61%
1/12/1984	15.60%	11.30%	4.30%
1/18/1984	13.75%	11.32%	2.43%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.36%	4.74%
1/31/1984	15.25%	11.37%	3.88%
2/1/1984	14.80%	11.38%	3.42%
2/6/1984	13.75%	11.40%	2.35%
2/6/1984	14.75%	11.40%	3.35%
2/9/1984	15.25%	11.42%	3.83%
2/15/1984	15.70%	11.44%	4.26%
2/20/1984	15.00%	11.45%	3.55%
2/20/1984	15.00%	11.45%	3.55%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
2/22/1984	14.75%	11.47%	3.28%
2/28/1984	14.50%	11.50%	3.00%
3/2/1984	14.25%	11.53%	2.72%
3/20/1984	16.00%	11.64%	4.36%
3/23/1984	15.50%	11.66%	3.84%
3/26/1984	14.71%	11.67%	3.04%
4/2/1984	15.50%	11.71%	3.79%
4/6/1984	14.74%	11.75%	2.99%
4/11/1984	15.72%	11.77%	3.95%
4/17/1984	15.00%	11.80%	3.20%
4/18/1984	16.20%	11.81%	4.39%
4/25/1984	14.64%	11.85%	2.79%
4/30/1984	14.40%	11.87%	2.53%
5/16/1984	14.69%	11.98%	2.71%
5/16/1984	15.00%	11.98%	3.02%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.15%	3.10%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.25%	3.00%
7/2/1984	13.35%	12.26%	1.09%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.32%	4.18%
7/13/1984	16.25%	12.33%	3.92%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.30%	12.35%	2.95%
7/18/1984	15.50%	12.35%	3.15%
7/19/1984	14.30%	12.36%	1.94%
7/24/1984	16.79%	12.39%	4.40%
7/31/1984	16.00%	12.42%	3.58%
8/3/1984	14.25%	12.44%	1.81%
8/17/1984	14.30%	12.48%	1.82%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.50%	3.80%
8/31/1984	15.55%	12.52%	3.03%
9/6/1984	16.00%	12.53%	3.47%
9/10/1984	14.75%	12.54%	2.21%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.55%	4.83%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	15.00%	12.57%	2.43%
9/28/1984	16.25%	12.57%	3.68%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.58%	3.02%
10/22/1984	15.00%	12.58%	2.42%
10/26/1984	16.40%	12.58%	3.82%
10/31/1984	16.25%	12.58%	3.67%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.58%	3.17%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
11/20/1984	15.25%	12.57%	2.68%
11/20/1984	15.92%	12.57%	3.35%
11/23/1984	15.00%	12.57%	2.43%
11/28/1984	16.15%	12.56%	3.59%
12/3/1984	15.80%	12.56%	3.24%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.53%	3.87%
12/19/1984	14.75%	12.53%	2.22%
12/19/1984	15.00%	12.53%	2.47%
12/20/1984	16.00%	12.52%	3.48%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.36%	2.11%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.29%	4.56%
3/14/1985	15.50%	12.26%	3.24%
3/15/1985	15.62%	12.26%	3.36%
3/29/1985	15.62%	12.17%	3.45%
4/3/1985	14.60%	12.14%	2.46%
4/9/1985	15.50%	12.11%	3.39%
4/16/1985	15.70%	12.06%	3.64%
4/22/1985	14.00%	12.02%	1.98%
4/26/1985	15.50%	11.99%	3.51%
4/29/1985	15.00%	11.98%	3.02%
5/2/1985	14.68%	11.94%	2.74%
5/8/1985	15.62%	11.90%	3.72%
5/10/1985	16.50%	11.88%	4.62%
5/29/1985	14.61%	11.74%	2.87%
5/31/1985	16.00%	11.72%	4.28%
6/14/1985	15.50%	11.61%	3.89%
7/9/1985	15.00%	11.45%	3.55%
7/16/1985	14.50%	11.40%	3.10%
7/26/1985	14.50%	11.33%	3.17%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.27%	3.73%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.15%	3.35%
9/9/1985	14.60%	11.11%	3.49%
9/9/1985	14.90%	11.11%	3.79%
9/17/1985	14.90%	11.09%	3.81%
9/23/1985	15.00%	11.07%	3.93%
9/27/1985	15.50%	11.05%	4.45%
9/27/1985	15.80%	11.05%	4.75%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
10/2/1985	14.00%	11.04%	2.96%
10/2/1985	14.75%	11.04%	3.71%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.82%	10.96%	4.86%
10/24/1985	15.85%	10.96%	4.89%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.95%	5.70%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.92%	3.58%
11/7/1985	15.50%	10.90%	4.60%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.70%	4.30%
12/20/1985	14.50%	10.68%	3.82%
12/20/1985	14.50%	10.68%	3.82%
12/20/1985	15.00%	10.68%	4.32%
1/24/1986	15.40%	10.41%	4.99%
1/31/1986	15.00%	10.36%	4.64%
2/5/1986	15.00%	10.33%	4.67%
2/5/1986	15.75%	10.33%	5.42%
2/10/1986	13.30%	10.30%	3.00%
2/11/1986	12.50%	10.28%	2.22%
2/14/1986	14.40%	10.25%	4.15%
2/18/1986	16.00%	10.24%	5.76%
2/24/1986	14.50%	10.18%	4.32%
2/26/1986	14.00%	10.16%	3.84%
3/5/1986	14.90%	10.08%	4.82%
3/11/1986	14.50%	10.02%	4.48%
3/12/1986	13.50%	10.01%	3.49%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.83%	4.17%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/14/1986	13.40%	9.69%	3.71%
4/23/1986	15.00%	9.58%	5.42%
5/16/1986	14.50%	9.33%	5.17%
5/16/1986	14.50%	9.33%	5.17%
5/29/1986	13.90%	9.20%	4.70%
5/30/1986	15.10%	9.19%	5.91%
6/2/1986	12.81%	9.17%	3.64%
6/11/1986	14.00%	9.08%	4.92%
6/24/1986	16.63%	8.94%	7.69%
6/26/1986	12.00%	8.91%	3.09%
6/26/1986	14.75%	8.91%	5.84%
6/30/1986	13.00%	8.88%	4.12%
7/10/1986	14.34%	8.76%	5.58%
7/11/1986	12.75%	8.74%	4.01%
7/14/1986	12.60%	8.72%	3.88%
7/17/1986	12.40%	8.67%	3.73%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
7/25/1986	14.25%	8.58%	5.67%
8/6/1986	13.50%	8.45%	5.05%
8/14/1986	13.50%	8.36%	5.14%
9/16/1986	12.75%	8.07%	4.68%
9/19/1986	13.25%	8.04%	5.21%
10/1/1986	14.00%	7.96%	6.04%
10/3/1986	13.40%	7.94%	5.46%
10/31/1986	13.50%	7.78%	5.72%
11/5/1986	13.00%	7.76%	5.24%
12/3/1986	12.90%	7.59%	5.31%
12/4/1986	14.44%	7.58%	6.86%
12/16/1986	13.60%	7.53%	6.07%
12/22/1986	13.80%	7.51%	6.29%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.47%	4.93%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.47%	5.53%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.83%	7.17%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.86%	5.04%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/27/1987	13.00%	7.92%	5.08%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/31/1987	12.98%	7.94%	5.04%
8/26/1987	12.63%	8.05%	4.58%
8/26/1987	12.75%	8.05%	4.70%
8/27/1987	13.25%	8.06%	5.19%
9/9/1987	13.00%	8.13%	4.87%
9/30/1987	12.75%	8.30%	4.45%
9/30/1987	13.00%	8.30%	4.70%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.43%	4.57%
11/2/1987	13.00%	8.54%	4.46%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
11/19/1987	13.00%	8.63%	4.37%
11/30/1987	12.00%	8.68%	3.32%
12/3/1987	14.20%	8.70%	5.50%
12/15/1987	13.25%	8.77%	4.48%
12/16/1987	13.50%	8.78%	4.72%
12/16/1987	13.72%	8.78%	4.94%
12/17/1987	11.75%	8.78%	2.97%
12/18/1987	13.50%	8.79%	4.71%
12/21/1987	12.01%	8.80%	3.21%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.75%	8.81%	3.94%
12/22/1987	13.00%	8.81%	4.19%
1/20/1988	13.80%	8.93%	4.87%
1/26/1988	13.90%	8.95%	4.95%
1/29/1988	13.20%	8.95%	4.25%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.95%	2.01%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	9.00%	3.75%
7/1/1988	12.75%	9.00%	3.75%
7/20/1988	13.40%	8.97%	4.43%
8/5/1988	12.75%	8.92%	3.83%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.01%	3.99%
12/20/1988	12.25%	9.02%	3.23%
12/20/1988	13.00%	9.02%	3.98%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.03%	4.37%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.01%	4.19%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.92%	4.33%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.49%	4.51%
12/15/1989	13.00%	8.34%	4.66%
12/20/1989	12.90%	8.32%	4.58%
12/21/1989	12.90%	8.32%	4.58%
12/27/1989	12.50%	8.30%	4.20%
12/27/1989	13.00%	8.30%	4.70%
1/10/1990	12.80%	8.25%	4.55%
1/11/1990	12.90%	8.24%	4.66%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.20%	3.80%
2/9/1990	12.10%	8.18%	3.92%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.31%	4.89%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.10%	8.34%	3.76%
7/6/1990	12.35%	8.34%	4.01%
8/10/1990	12.55%	8.40%	4.15%
8/16/1990	13.21%	8.42%	4.79%
8/22/1990	13.10%	8.44%	4.66%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.62%	4.22%
10/19/1990	13.00%	8.66%	4.34%
10/25/1990	12.30%	8.67%	3.63%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.61%	3.89%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.58%	4.42%
2/14/1991	12.72%	8.57%	4.15%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	12.30%	8.52%	3.78%
3/8/1991	13.00%	8.52%	4.48%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.44%	4.31%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.39%	3.31%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.38%	3.62%
7/3/1991	12.50%	8.37%	4.13%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.50%	8.20%	4.30%
10/23/1991	12.55%	8.20%	4.35%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.50%	8.18%	4.32%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%
1/27/1992	12.65%	8.06%	4.59%
1/31/1992	12.00%	8.05%	3.95%
2/11/1992	12.40%	8.03%	4.37%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.99%	3.44%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.94%	3.51%
4/10/1992	11.50%	7.94%	3.56%
4/14/1992	11.50%	7.93%	3.57%
5/5/1992	11.50%	7.90%	3.60%
5/12/1992	11.87%	7.89%	3.98%
5/12/1992	12.46%	7.89%	4.57%
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	11.90%	7.84%	4.06%
7/13/1992	13.50%	7.84%	5.66%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.70%	5.46%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.30%	7.65%	4.65%
12/22/1992	12.40%	7.65%	4.75%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.63%	4.27%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	11.80%	7.48%	4.32%
2/26/1993	12.20%	7.48%	4.72%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.23%	4.27%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.96%	4.54%
9/21/1993	10.50%	6.81%	3.69%
9/29/1993	11.47%	6.77%	4.70%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.61%	4.19%
11/12/1993	12.00%	6.57%	5.43%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.45%	3.62%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	11.25%	6.36%	4.89%
2/25/1994	12.00%	6.36%	5.64%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.35%	4.65%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.53%	4.47%
6/27/1994	11.40%	6.64%	4.76%
8/5/1994	12.75%	6.87%	5.88%
10/31/1994	10.00%	7.32%	2.68%
11/9/1994	10.85%	7.38%	3.47%
11/9/1994	10.85%	7.38%	3.47%
11/18/1994	11.20%	7.45%	3.75%
11/22/1994	11.60%	7.46%	4.14%
11/28/1994	11.06%	7.49%	3.57%
12/8/1994	11.50%	7.54%	3.96%
12/8/1994	11.70%	7.54%	4.16%
12/14/1994	10.95%	7.56%	3.39%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.57%	3.93%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.68%	3.32%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.71%	3.79%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
4/6/1995	11.10%	7.71%	3.39%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.52%	3.58%
9/11/1995	11.30%	7.21%	4.09%
9/27/1995	11.30%	7.13%	4.17%
9/27/1995	11.50%	7.13%	4.37%
9/27/1995	11.75%	7.13%	4.62%
9/29/1995	11.00%	7.12%	3.88%
11/9/1995	11.38%	6.90%	4.48%
11/9/1995	12.36%	6.90%	5.46%
11/17/1995	11.00%	6.86%	4.14%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.75%	4.65%
12/20/1995	11.60%	6.70%	4.90%
12/27/1995	12.00%	6.67%	5.33%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.44%	4.81%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.44%	4.81%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.70%	4.30%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.80%	4.20%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.83%	4.92%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.61%	4.39%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.40%	6.35%
3/2/1998	11.25%	6.29%	4.96%
3/6/1998	10.75%	6.27%	4.48%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
3/20/1998	10.50%	6.23%	4.27%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.55%	6.65%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.39%	4.91%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.51%	5.24%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.89%	5.21%
1/7/2000	11.50%	6.04%	5.46%
1/7/2000	11.50%	6.04%	5.46%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.19%	5.06%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	11.00%	5.48%	5.52%
6/20/2002	12.30%	5.48%	6.82%
7/15/2002	11.00%	5.47%	5.53%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.05%	7.25%
3/6/2003	10.75%	5.03%	5.72%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.99%	7.01%
4/3/2003	12.00%	4.96%	7.04%
4/15/2003	11.15%	4.94%	6.21%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.80%	4.70%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	9.85%	4.93%	4.92%
12/17/2003	10.70%	4.93%	5.77%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.98%	5.77%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%
5/25/2004	10.25%	5.08%	5.17%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.06%	5.44%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.06%	5.91%
12/21/2004	11.25%	5.07%	6.18%
12/21/2004	11.50%	5.07%	6.43%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.07%	4.78%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.90%	5.40%
4/4/2005	10.00%	4.88%	5.12%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.77%	5.98%
5/26/2005	9.75%	4.76%	4.99%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.65%	6.85%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.62%	5.51%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.54%	6.21%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.55%	5.74%
12/21/2005	10.40%	4.55%	5.85%
12/22/2005	11.00%	4.54%	6.46%
12/22/2005	11.15%	4.54%	6.61%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.82%	5.38%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.89%	5.65%
9/14/2006	10.00%	4.90%	5.10%
10/6/2006	9.67%	4.92%	4.75%
11/20/2006	9.80%	4.95%	4.85%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.25%	4.95%	5.30%
12/1/2006	10.50%	4.95%	5.55%
12/7/2006	10.75%	4.95%	5.80%
12/21/2006	10.90%	4.95%	5.95%
12/21/2006	11.25%	4.95%	6.30%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.87%	6.48%
3/22/2007	9.75%	4.87%	4.88%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.81%	5.39%
5/22/2007	10.50%	4.81%	5.69%
5/23/2007	10.70%	4.81%	5.89%
5/25/2007	9.67%	4.81%	4.86%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.90%	4.86%	5.04%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.85%	5.35%
12/20/2007	10.20%	4.85%	5.35%
12/20/2007	11.00%	4.85%	6.15%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.82%	5.93%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.69%	4.41%
3/31/2008	12.12%	4.67%	7.45%
4/22/2008	10.25%	4.61%	5.64%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.59%	6.11%
5/19/2008	11.00%	4.57%	6.43%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	10.50%	4.54%	5.96%
6/27/2008	11.04%	4.54%	6.50%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.52%	4.88%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.51%	5.74%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.48%	5.72%
10/8/2008	10.15%	4.46%	5.69%
10/15/2008	10.10%	4.46%	5.64%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.40%	5.85%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/14/2009	10.60%	4.15%	6.45%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.08%	6.42%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.97%	6.53%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.86%	7.24%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.79%	6.21%
4/30/2009	11.25%	3.78%	7.47%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.75%	6.50%
5/28/2009	10.50%	3.75%	6.75%
5/29/2009	10.50%	3.75%	6.75%
6/22/2009	10.00%	3.77%	6.23%
6/24/2009	10.80%	3.77%	7.03%
7/8/2009	10.63%	3.77%	6.86%
7/17/2009	10.50%	3.78%	6.72%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.01%	6.69%
10/23/2009	10.88%	4.05%	6.83%
11/2/2009	10.70%	4.09%	6.61%
11/3/2009	10.70%	4.09%	6.61%
11/24/2009	10.25%	4.15%	6.10%
11/25/2009	10.75%	4.15%	6.60%
11/30/2009	10.35%	4.16%	6.19%
12/3/2009	10.50%	4.17%	6.33%
12/7/2009	10.70%	4.18%	6.52%
12/16/2009	10.90%	4.21%	6.69%
12/16/2009	11.00%	4.21%	6.79%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.27%	6.53%
1/11/2010	11.00%	4.30%	6.70%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.70%	4.35%	6.35%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/11/2010	12.30%	4.42%	7.88%
3/11/2010	12.30%	4.42%	7.88%
3/17/2010	10.00%	4.42%	5.58%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.46%	5.84%
5/12/2010	10.30%	4.46%	5.84%
5/28/2010	10.10%	4.44%	5.66%
5/28/2010	10.20%	4.44%	5.76%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	9.67%	4.43%	5.24%
6/28/2010	10.50%	4.43%	6.07%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.53%	4.43%	6.10%
7/15/2010	10.70%	4.43%	6.27%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.33%	5.67%
9/16/2010	10.00%	4.33%	5.67%
9/30/2010	9.75%	4.29%	5.46%
9/30/2010	11.00%	4.29%	6.71%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.20%	6.50%
11/19/2010	10.20%	4.18%	6.02%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
11/22/2010	10.00%	4.18%	5.82%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.16%	5.70%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.15%	5.85%
12/20/2010	10.60%	4.15%	6.45%
12/21/2010	10.30%	4.15%	6.15%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.13%	6.17%
1/13/2011	10.30%	4.13%	6.17%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.12%	5.48%
2/3/2011	10.00%	4.12%	5.88%
2/25/2011	10.00%	4.14%	5.86%
3/22/2011	12.30%	4.17%	8.13%
3/22/2011	12.30%	4.17%	8.13%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.23%	5.44%
4/27/2011	10.40%	4.23%	6.17%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.31%	4.89%
6/17/2011	9.95%	4.31%	5.64%
7/13/2011	10.20%	4.36%	5.84%
8/1/2011	9.20%	4.38%	4.82%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.37%	5.63%
8/12/2011	10.35%	4.37%	5.98%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.88%	7.02%
11/30/2011	10.90%	3.88%	7.02%
12/14/2011	10.00%	3.80%	6.20%
12/14/2011	10.30%	3.80%	6.50%
12/20/2011	10.20%	3.77%	6.43%
12/21/2011	10.20%	3.76%	6.44%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.75%	6.44%
1/3/2012	11.40%	3.69%	7.71%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.56%	6.94%
2/2/2012	11.40%	3.53%	7.87%
2/15/2012	10.20%	3.48%	6.72%
2/23/2012	9.90%	3.44%	6.46%
2/27/2012	10.25%	3.43%	6.82%
2/29/2012	10.40%	3.42%	6.98%
3/16/2012	12.40%	3.36%	9.04%
3/20/2012	11.40%	3.35%	8.05%
3/23/2012	11.40%	3.34%	8.06%
3/29/2012	10.37%	3.32%	7.05%
4/4/2012	10.00%	3.30%	6.70%
4/26/2012	10.00%	3.21%	6.79%
5/2/2012	10.00%	3.19%	6.81%
5/7/2012	9.80%	3.17%	6.63%
5/15/2012	10.00%	3.15%	6.85%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.08%	7.22%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.06%	6.54%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.31%	3.01%	6.30%
7/20/2012	9.81%	3.01%	6.80%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.75%	2.90%	6.85%
11/29/2012	9.88%	2.90%	6.98%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	9.50%	2.88%	6.62%
12/13/2012	10.50%	2.88%	7.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.88%	6.83%
12/19/2012	10.25%	2.88%	7.37%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] Average 30-Year Treasury Yield	[9] Risk Premium
12/20/2012	9.50%	2.88%	6.62%
12/20/2012	9.80%	2.88%	6.92%
12/20/2012	10.25%	2.88%	7.37%
12/20/2012	10.25%	2.88%	7.37%
12/20/2012	10.30%	2.88%	7.42%
12/20/2012	10.40%	2.88%	7.52%
12/20/2012	10.45%	2.88%	7.57%
12/20/2012	11.40%	2.88%	8.52%
12/21/2012	10.20%	2.88%	7.32%
12/26/2012	9.80%	2.87%	6.93%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
2/13/2013	10.20%	2.85%	7.35%
2/19/2013	11.40%	2.85%	8.55%
2/19/2013	11.40%	2.85%	8.55%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/5/2013	9.70%	2.86%	6.84%
3/12/2013	11.40%	2.87%	8.53%
3/14/2013	9.30%	2.88%	6.42%
3/22/2013	12.40%	2.89%	9.51%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.07%	6.29%
		Average:	4.43%
		Count:	1,410

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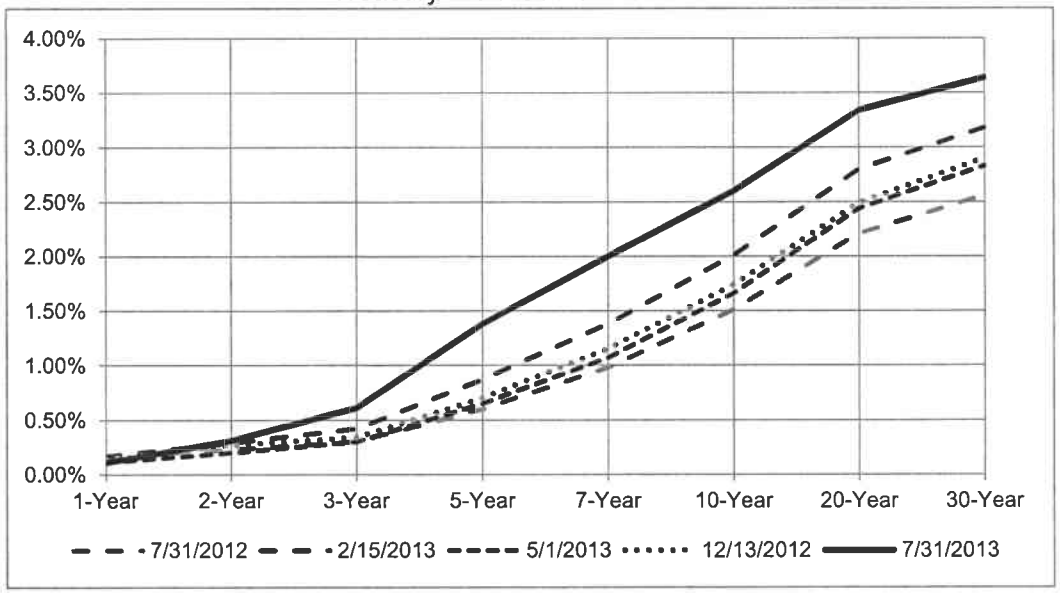
Treasury Yield Curve and Selected Interest Rates



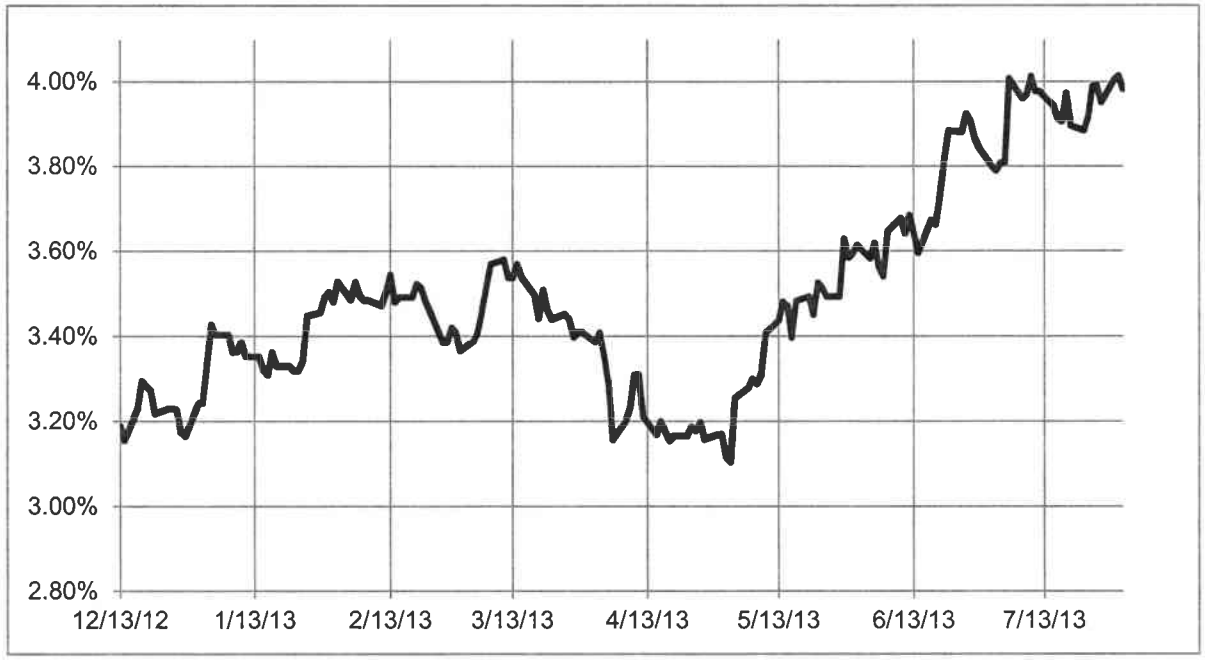
Summary of Selected Interest Rates (30-Day Average)

	7/12/2012	[1] 12/13/2012	7/31/2013
30-Year Treasury Yield	2.68%	2.81%	3.59%
10-Year Treasury Yield	1.61%	1.65%	2.56%
Moody's A Utility Bond Index	4.06%	3.87%	4.69%
Moody's Baa Utility Bond Index	4.92%	4.44%	5.22%

Notes:
[1] Date of Order for Docket No. 120015-EI

Sources: Federal Reserve, Bloomberg Professional

Forward 27-Year Treasury Yield Curve (in 3 Years)



Source: Federal Reserve

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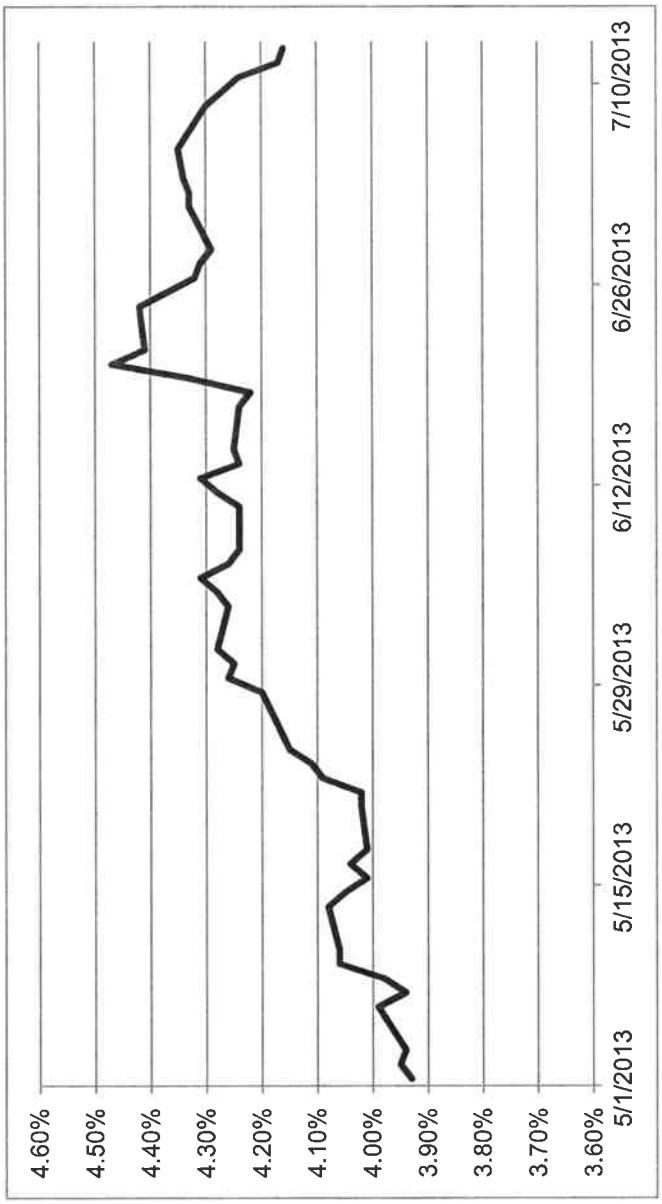
Hevert Proxy Group Dividend Yield



Source: SNL Financial

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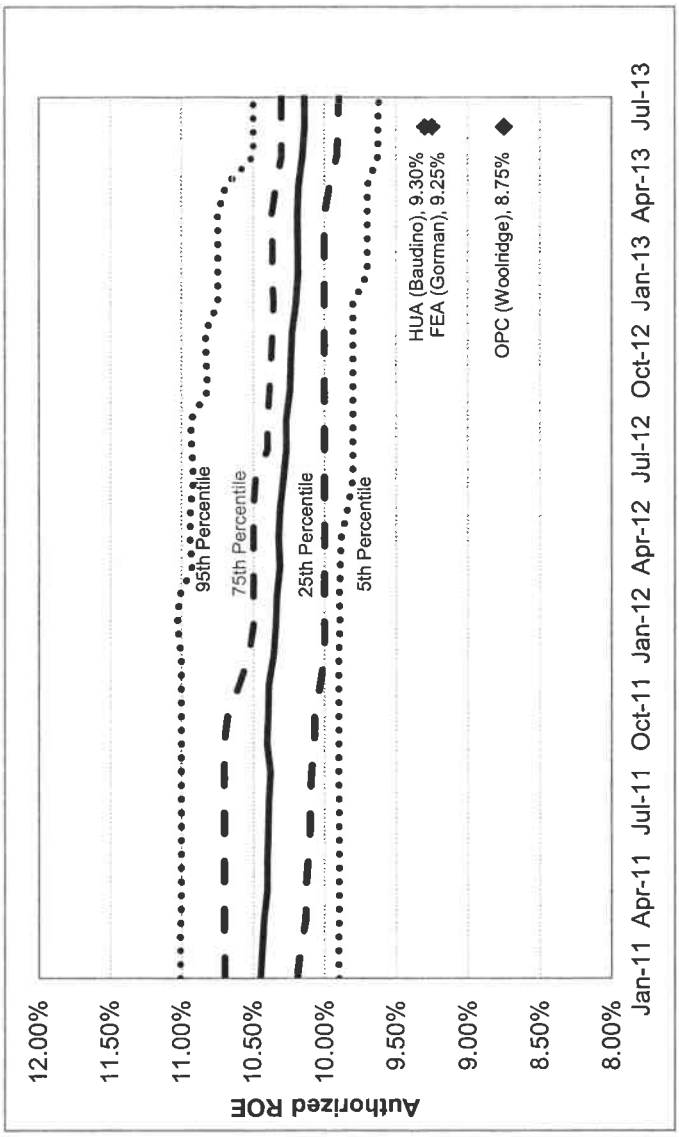
Recently Authorized ROEs for Vertically Integrated Electric Utilities



Source: Regulatory Research Associates

Adjustment of Mr. Gorman's Multi-Stage DCF Model
Re-Creation Of Schedule MPG-9

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Second-Stage Growth Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Multi-Stage Growth DCF
American Electric Power Company, Inc.	AEP	$48.16	$1.96	3.74%	3.93%	4.13%	4.32%	4.51%	4.71%	4.90%	8.86%
Cleco Corp.	CNL	$46.74	$1.45	8.00%	7.48%	6.97%	6.45%	5.93%	5.42%	4.90%	8.85%
Empire District Electric	EDE	$22.35	$1.00	3.00%	3.32%	3.63%	3.95%	4.27%	4.58%	4.90%	9.06%
Great Plains Energy Inc.	GXP	$23.20	$0.87	5.44%	5.35%	5.26%	5.17%	5.08%	4.99%	4.90%	8.97%
IDACORP, Inc.	IDA	$48.06	$1.52	4.00%	4.15%	4.30%	4.45%	4.60%	4.75%	4.90%	8.02%
Otter Tail Corporation	OTTR	$29.64	$1.19	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	9.41%
Pinnacle West Capital Corp.	PNW	$58.26	$2.18	4.78%	4.80%	4.82%	4.84%	4.86%	4.88%	4.90%	8.79%
PNM Resources, Inc.	PNM	$22.90	$0.66	6.56%	6.28%	6.00%	5.73%	5.45%	5.18%	4.90%	8.26%
Portland General Electric Company	POR	$31.06	$1.08	6.32%	6.09%	5.85%	5.61%	5.37%	5.14%	4.90%	8.89%
Southern Company	SO	$46.12	$2.03	4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	9.52%
Westar Energy, Inc.	WR	$32.90	$1.36	4.65%	4.69%	4.74%	4.78%	4.82%	4.86%	4.90%	9.17%
Mean				5.22%	5.17%	5.11%	5.06%	5.01%	4.95%	4.90%	8.89%
Median				4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	8.89%

Notes:
[1] 13-week average stock price; Source: Schedule MPG-9
[2] Source: Schedule MPG-9
[3] Source: Schedule MPG-9
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Source: Schedule MPG-9
[10] IRR based on stock price ([1]) and 200 years of projected dividends

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Adjustment of Mr. Gorman's Multi-Stage DCF Model
Adjust The IRR Calculation To Reflect The Mid-Year Convention

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Multi-Stage Growth DCF
					Second-Stage Growth						
American Electric Power Company, Inc.	AEP	$48.16	$1.96	3.74%	3.93%	4.13%	4.32%	4.51%	4.71%	4.90%	9.04%
Cleco Corp.	CNL	$46.74	$1.45	8.00%	7.48%	6.97%	6.45%	5.93%	5.42%	4.90%	9.02%
Empire District Electric	EDE	$22.35	$1.00	3.00%	3.32%	3.63%	3.95%	4.27%	4.58%	4.90%	9.25%
Great Plains Energy Inc.	GXP	$23.20	$0.87	5.44%	5.35%	5.26%	5.17%	5.08%	4.99%	4.90%	9.14%
IDACORP, Inc.	IDA	$48.06	$1.52	4.00%	4.15%	4.30%	4.45%	4.60%	4.75%	4.90%	8.14%
Otter Tail Corporation	OTTR	$29.64	$1.19	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	9.61%
Pinnacle West Capital Corp.	PNW	$58.26	$2.18	4.78%	4.80%	4.82%	4.84%	4.86%	4.88%	4.90%	8.96%
PNM Resources, Inc.	PNM	$22.90	$0.66	6.56%	6.28%	6.00%	5.73%	5.45%	5.18%	4.90%	8.39%
Portland General Electric Company	POR	$31.06	$1.08	6.32%	6.09%	5.85%	5.61%	5.37%	5.14%	4.90%	9.06%
Southern Company	SO	$46.12	$2.03	4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	9.74%
Westar Energy, Inc.	WR	$32.90	$1.36	4.65%	4.69%	4.74%	4.78%	4.82%	4.86%	4.90%	9.36%
Mean				5.22%	5.17%	5.11%	5.06%	5.01%	4.95%	4.90%	9.06%
Median				4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	9.06%

Notes:
[1] 13-week average stock price; Source: Schedule MPG-9
[2] Source: Schedule MPG-9
[3] Source: Schedule MPG-9
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Source: Schedule MPG-9
[10] IRR based on stock price ([1]) and 200 years of projected dividends using the mid-year convention

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Adjustment of Mr. Gorman's Multi-Stage DCF Model
Add Fourth Stage to Reflect Blue Chip Forecast Period - Mr. Hevert's Long-Term Growth Rate

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Second-Stage Growth Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Fourth-Stage Growth	[11] Multi-Stage Growth DCF
American Electric Power Company, Inc.	AEP	$48.16	$1.96	3.74%	3.93%	4.13%	4.32%	4.51%	4.71%	4.90%	5.59%	9.34%
Cleco Corp.	CNL	$46.74	$1.45	8.00%	7.48%	6.97%	6.45%	5.93%	5.42%	4.90%	5.59%	9.33%
Empire District Electric	EDE	$22.35	$1.00	3.00%	3.32%	3.63%	3.95%	4.27%	4.58%	4.90%	5.59%	9.53%
Great Plains Energy Inc.	GXP	$23.20	$0.87	5.44%	5.35%	5.26%	5.17%	5.08%	4.99%	4.90%	5.59%	9.44%
IDACORP, Inc.	IDA	$48.06	$1.52	4.00%	4.15%	4.30%	4.45%	4.60%	4.75%	4.90%	5.59%	8.53%
Otter Tail Corporation	OTTR	$29.64	$1.19	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	5.59%	9.86%
Pinnacle West Capital Corp.	PNW	$58.26	$2.18	4.78%	4.80%	4.82%	4.84%	4.86%	4.88%	4.90%	5.59%	9.27%
PNM Resources, Inc.	PNM	$22.90	$0.66	6.56%	6.28%	6.00%	5.73%	5.45%	5.18%	4.90%	5.59%	8.76%
Portland General Electric Company	POR	$31.06	$1.08	6.32%	6.09%	5.85%	5.61%	5.37%	5.14%	4.90%	5.59%	9.36%
Southern Company	SO	$46.12	$2.03	4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	5.59%	9.97%
Westar Energy, Inc.	WR	$32.90	$1.36	4.65%	4.69%	4.74%	4.78%	4.82%	4.86%	4.90%	5.59%	9.63%
Mean				5.22%	5.17%	5.11%	5.06%	5.01%	4.95%	4.90%	5.59%	9.37%
Median				4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	5.59%	9.36%

Notes:
[1] 13-week average stock price; Source: Schedule MPG-9
[2] Source: Schedule MPG-9
[3] Source: Schedule MPG-9
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Source: Schedule MPG-9
[10] Source: Document No. 1
[11] IRR based on stock price ([1]) and 200 years of projected dividends using the mid-year convention

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Adjustment of Mr. Gorman's Multi-Stage DCF Model
Add Fourth Stage to Reflect Blue Chip Forecast Period - Long-Term Capital Appreciation Rate

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Second-Stage Growth Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Fourth-Stage Growth	[11] Multi-Stage Growth DCF
American Electric Power Company, Inc.	AEP	$48.16	$1.96	3.74%	3.93%	4.13%	4.32%	4.51%	4.71%	4.90%	7.50%	10.72%
Cleco Corp.	CNL	$46.74	$1.45	8.00%	7.48%	6.97%	6.45%	5.93%	5.42%	4.90%	7.50%	10.71%
Empire District Electric	EDE	$22.35	$1.00	3.00%	3.32%	3.63%	3.95%	4.27%	4.58%	4.90%	7.50%	10.88%
Great Plains Energy Inc.	GXP	$23.20	$0.87	5.44%	5.35%	5.26%	5.17%	5.08%	4.99%	4.90%	7.50%	10.81%
IDACORP, Inc.	IDA	$48.06	$1.52	4.00%	4.15%	4.30%	4.45%	4.60%	4.75%	4.90%	7.50%	10.00%
Otter Tail Corporation	OTTR	$29.64	$1.19	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	7.50%	11.18%
Pinnacle West Capital Corp.	PNW	$58.26	$2.18	4.78%	4.80%	4.82%	4.84%	4.86%	4.88%	4.90%	7.50%	10.66%
PNM Resources, Inc.	PNM	$22.90	$0.66	6.56%	6.28%	6.00%	5.73%	5.45%	5.18%	4.90%	7.50%	10.20%
Portland General Electric Company	POR	$31.06	$1.08	6.32%	6.09%	5.85%	5.61%	5.37%	5.14%	4.90%	7.50%	10.74%
Southern Company	SO	$46.12	$2.03	4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	7.50%	11.28%
Westar Energy, Inc.	WR	$32.90	$1.36	4.65%	4.69%	4.74%	4.78%	4.82%	4.86%	4.90%	7.50%	10.98%
Mean				5.22%	5.17%	5.11%	5.06%	5.01%	4.95%	4.90%	7.50%	10.74%
Median				4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	7.50%	10.74%

Notes:
[1] 13-week average stock price; Source: Schedule MPG-9
[2] Source: Schedule MPG-9
[3] Source: Schedule MPG-9
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Source: Schedule MPG-9
[10] Source: Document No. 1
[11] IRR based on stock price ([1]) and 200 years of projected dividends using the mid-year convention

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Mr. Gorman's Multi-Stage DCF Growth Model
Implied Growth Rate to Produce Average Authorized ROE as DCF Result

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Second-Stage Growth Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Multi-Stage Growth DCF
American Electric Power Company, Inc.	AEP	$48.16	$1.96	3.74%	4.17%	4.60%	5.03%	5.45%	5.88%	6.31%	9.98%
Cleco Corp.	CNL	$46.74	$1.45	8.00%	7.72%	7.44%	7.16%	6.87%	6.59%	6.31%	9.97%
Empire District Electric	EDE	$22.35	$1.00	3.00%	3.55%	4.10%	4.66%	5.21%	5.76%	6.31%	10.17%
Great Plains Energy Inc.	GXP	$23.20	$0.87	5.44%	5.59%	5.73%	5.88%	6.02%	6.17%	6.31%	10.08%
IDACORP, Inc.	IDA	$48.06	$1.52	4.00%	4.39%	4.77%	5.16%	5.54%	5.93%	6.31%	9.19%
Otter Tail Corporation	OTTR	$29.64	$1.19	6.00%	6.05%	6.10%	6.16%	6.21%	6.26%	6.31%	10.50%
Pinnacle West Capital Corp.	PNW	$58.26	$2.18	4.78%	5.03%	5.29%	5.54%	5.80%	6.06%	6.31%	9.92%
PNM Resources, Inc.	PNM	$22.90	$0.66	6.56%	6.52%	6.48%	6.43%	6.39%	6.35%	6.31%	9.41%
Portland General Electric Company	POR	$31.06	$1.08	6.32%	6.32%	6.32%	6.32%	6.32%	6.31%	6.31%	10.01%
Southern Company	SO	$46.12	$2.03	4.92%	5.15%	5.38%	5.62%	5.85%	6.08%	6.31%	10.60%
Westar Energy, Inc.	WR	$32.90	$1.36	4.65%	4.93%	5.21%	5.48%	5.76%	6.04%	6.31%	10.27%
MEAN		$37.22	$1.39	5.22%	5.40%	5.58%	5.77%	5.95%	6.13%	6.31%	10.01%
MEDIAN		$32.90	$1.36	4.92%	5.15%	5.38%	5.62%	5.85%	6.08%	6.31%	10.01%

Notes:
[1] 13-week average stock price; Source: Exhibit MPG-9
[2] Source: Bloomberg Professional
[3] Source: Schedule MPG-9
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Implicit Growth Rate
[10] IRR based on stock price ([1]) and 200 years of projected dividends

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Step-By-Step Adjustment of Mr. Gorman's Multi-Stage DCF Model
Re-Creation Of Schedule MPG-9

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Second-Stage Growth Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Multi-Stage Growth DCF
American Electric Power Company, Inc.	AEP	$48.16	$1.96	3.74%	3.93%	4.13%	4.32%	4.51%	4.71%	4.90%	8.86%
Cleco Corp.	CNL	$46.74	$1.45	8.00%	7.48%	6.97%	6.45%	5.93%	5.42%	4.90%	8.85%
Empire District Electric	EDE	$22.35	$1.00	3.00%	3.32%	3.63%	3.95%	4.27%	4.58%	4.90%	9.06%
Great Plains Energy Inc.	GXP	$23.20	$0.87	5.44%	5.35%	5.26%	5.17%	5.08%	4.99%	4.90%	8.97%
IDACORP, Inc.	IDA	$48.06	$1.52	4.00%	4.15%	4.30%	4.45%	4.60%	4.75%	4.90%	8.02%
Otter Tail Corporation	OTTR	$29.64	$1.19	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	9.41%
Pinnacle West Capital Corp.	PNW	$58.26	$2.18	4.78%	4.80%	4.82%	4.84%	4.86%	4.88%	4.90%	8.79%
PNM Resources, Inc.	PNM	$22.90	$0.66	6.56%	6.28%	6.00%	5.73%	5.45%	5.18%	4.90%	8.26%
Portland General Electric Company	POR	$31.06	$1.08	6.32%	6.09%	5.85%	5.61%	5.37%	5.14%	4.90%	8.89%
Southern Company	SO	$46.12	$2.03	4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	9.52%
Westar Energy, Inc.	WR	$32.90	$1.36	4.65%	4.69%	4.74%	4.78%	4.82%	4.86%	4.90%	9.17%
Mean				5.22%	5.17%	5.11%	5.06%	5.01%	4.95%	4.90%	8.89%
Median				4.92%	4.92%	4.91%	4.91%	4.91%	4.90%	4.90%	8.89%

Notes:
[1] 13-week average stock price; Source: Schedule MPG-9
[2] Source: Schedule MPG-9
[3] Source: Schedule MPG-9
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Source: Schedule MPG-9
[10] IRR based on stock price ([1]) and 200 years of projected dividends

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Step-By-Step Adjustment of Mr. Gorman's Multi-Stage DCF Model
Step 1: Update Market Data To July 12, 2013

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Second-Stage Growth Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Multi-Stage Growth DCF
American Electric Power Company, Inc.	AEP	$47.41	$1.96	3.59%	3.81%	4.03%	4.25%	4.46%	4.68%	4.90%	8.89%
Cleco Corp.	CNL	$46.65	$1.45	8.00%	7.48%	6.97%	6.45%	5.93%	5.42%	4.90%	8.86%
Empire District Electric	EDE	$22.42	$1.00	3.00%	3.32%	3.63%	3.95%	4.27%	4.58%	4.90%	9.05%
Great Plains Energy Inc.	GXP	$23.23	$0.87	5.82%	5.66%	5.51%	5.36%	5.21%	5.05%	4.90%	9.06%
IDACORP, Inc.	IDA	$48.22	$1.52	4.00%	4.15%	4.30%	4.45%	4.60%	4.75%	4.90%	8.01%
Otter Tail Corporation	OTTR	$29.17	$1.19	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	9.48%
Pinnacle West Capital Corp.	PNW	$57.74	$2.18	4.77%	4.79%	4.81%	4.83%	4.86%	4.88%	4.90%	8.82%
PNM Resources, Inc.	PNM	$22.69	$0.66	6.65%	6.36%	6.07%	5.78%	5.48%	5.19%	4.90%	8.31%
Portland General Electric Company	POR	$31.14	$1.10	5.96%	5.78%	5.60%	5.43%	5.25%	5.08%	4.90%	8.86%
Southern Company	SO	$45.50	$2.03	4.66%	4.70%	4.74%	4.78%	4.82%	4.86%	4.90%	9.51%
Westar Energy, Inc.	WR	$32.62	$1.36	3.80%	3.99%	4.17%	4.35%	4.53%	4.72%	4.90%	8.98%
Mean				5.11%	5.08%	5.04%	5.01%	4.97%	4.94%	4.90%	8.89%
Median				4.77%	4.79%	4.81%	4.83%	4.86%	4.88%	4.90%	8.89%

Notes:
[1] 13-week average stock price through July 12, 2013; Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Updates to Zacks, SNL Financial, First Call (Thomson)
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Source: Schedule MPG-9
[10] IRR based on stock price ([1]) and 200 years of projected dividends

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Step-By-Step Adjustment of Mr. Gorman's Multi-Stage DCF Model
Step 2: Adjust The IRR Calculation To Reflect The Mid-Year Convention

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Multi-Stage Growth DCF
					Second-Stage Growth						
American Electric Power Company, Inc.	AEP	$47.41	$1.96	3.59%	3.81%	4.03%	4.25%	4.46%	4.68%	4.90%	9.06%
Cleco Corp.	CNL	$46.65	$1.45	8.00%	7.48%	6.97%	6.45%	5.93%	5.42%	4.90%	9.02%
Empire District Electric	EDE	$22.42	$1.00	3.00%	3.32%	3.63%	3.95%	4.27%	4.58%	4.90%	9.23%
Great Plains Energy Inc.	GXP	$23.23	$0.87	5.82%	5.66%	5.51%	5.36%	5.21%	5.05%	4.90%	9.24%
IDACORP, Inc.	IDA	$48.22	$1.52	4.00%	4.15%	4.30%	4.45%	4.60%	4.75%	4.90%	8.13%
Otter Tail Corporation	OTTR	$29.17	$1.19	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	9.69%
Pinnacle West Capital Corp.	PNW	$57.74	$2.18	4.77%	4.79%	4.81%	4.83%	4.86%	4.88%	4.90%	8.99%
PNM Resources, Inc.	PNM	$22.69	$0.66	6.65%	6.36%	6.07%	5.78%	5.48%	5.19%	4.90%	8.44%
Portland General Electric Company	POR	$31.14	$1.10	5.96%	5.78%	5.60%	5.43%	5.25%	5.08%	4.90%	9.03%
Southern Company	SO	$45.50	$2.03	4.66%	4.70%	4.74%	4.78%	4.82%	4.86%	4.90%	9.72%
Westar Energy, Inc.	WR	$32.62	$1.36	3.80%	3.99%	4.17%	4.35%	4.53%	4.72%	4.90%	9.16%
Mean				5.11%	5.08%	5.04%	5.01%	4.97%	4.94%	4.90%	9.06%
Median				4.77%	4.79%	4.81%	4.83%	4.86%	4.88%	4.90%	9.06%

Notes:
[1] 13-week average stock price through July 12, 2013; Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Updates to Zacks, SNL Financial, First Call (Thomson)
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Source: Schedule MPG-9
[10] IRR based on stock price ([1]) and 200 years of projected dividends using the mid-year convention

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Step-By-Step Adjustment of Mr. Gorman's Multi-Stage DCF Model
Step 3: Correct Long-Term Growth Estimate

Company	Ticker	[1] Stock Price	[2] Annualized Dividend	[3] First-Stage Growth	[4] Second-Stage Growth Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] Third-Stage Growth	[10] Multi-Stage Growth DCF
American Electric Power Company, Inc.	AEP	$47.41	$1.96	3.59%	3.93%	4.26%	4.59%	4.92%	5.25%	5.59%	9.61%
Cleco Corp.	CNL	$46.65	$1.45	8.00%	7.60%	7.20%	6.79%	6.39%	5.99%	5.59%	9.57%
Empire District Electric	EDE	$22.42	$1.00	3.00%	3.43%	3.86%	4.29%	4.72%	5.16%	5.59%	9.77%
Great Plains Energy Inc.	GXP	$23.23	$0.87	5.82%	5.78%	5.74%	5.70%	5.66%	5.62%	5.59%	9.78%
IDACORP, Inc.	IDA	$48.22	$1.52	4.00%	4.26%	4.53%	4.79%	5.06%	5.32%	5.59%	8.70%
Otter Tail Corporation	OTTR	$29.17	$1.19	6.00%	5.93%	5.86%	5.79%	5.72%	5.66%	5.59%	10.22%
Pinnacle West Capital Corp.	PNW	$57.74	$2.18	4.77%	4.90%	5.04%	5.18%	5.31%	5.45%	5.59%	9.54%
PNM Resources, Inc.	PNM	$22.69	$0.66	6.65%	6.47%	6.30%	6.12%	5.94%	5.76%	5.59%	9.00%
Portland General Electric Company	POR	$31.14	$1.10	5.96%	5.89%	5.83%	5.77%	5.71%	5.65%	5.59%	9.57%
Southern Company	SO	$45.50	$2.03	4.66%	4.81%	4.97%	5.12%	5.28%	5.43%	5.59%	10.25%
Westar Energy, Inc.	WR	$32.62	$1.36	3.80%	4.10%	4.40%	4.69%	4.99%	5.29%	5.59%	9.70%
Mean				5.11%	5.19%	5.27%	5.35%	5.43%	5.51%	5.59%	9.61%
Median				4.77%	4.90%	5.04%	5.18%	5.31%	5.45%	5.59%	9.61%

Notes:
[1] 13-week average stock price through July 12, 2013; Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Updates to Zacks, SNL Financial, First Call (Thomson)
[4] Equals [3] + ([9] - [3])/6
[5] Equals [4] + ([9] - [3])/6
[6] Equals [5] + ([9] - [3])/6
[7] Equals [6] + ([9] - [3])/6
[8] Equals [7] + ([9] - [3])/6
[9] Source: Document No. 2
[10] IRR based on stock price ([1]) and 200 years of projected dividends using the mid-year convention

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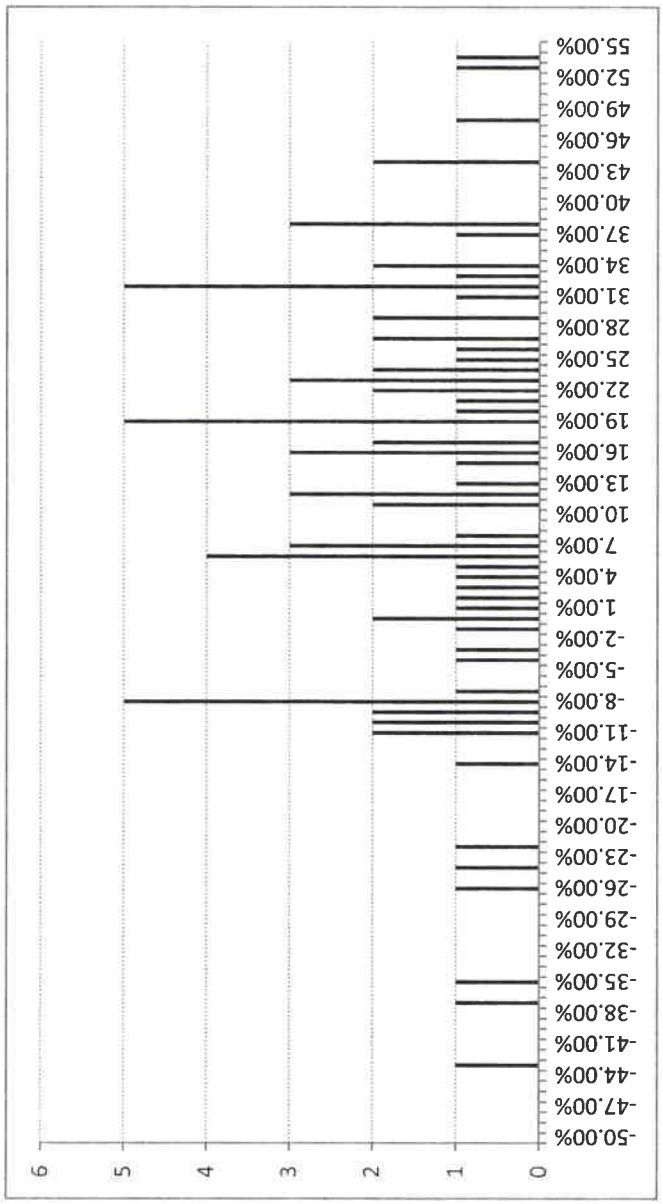
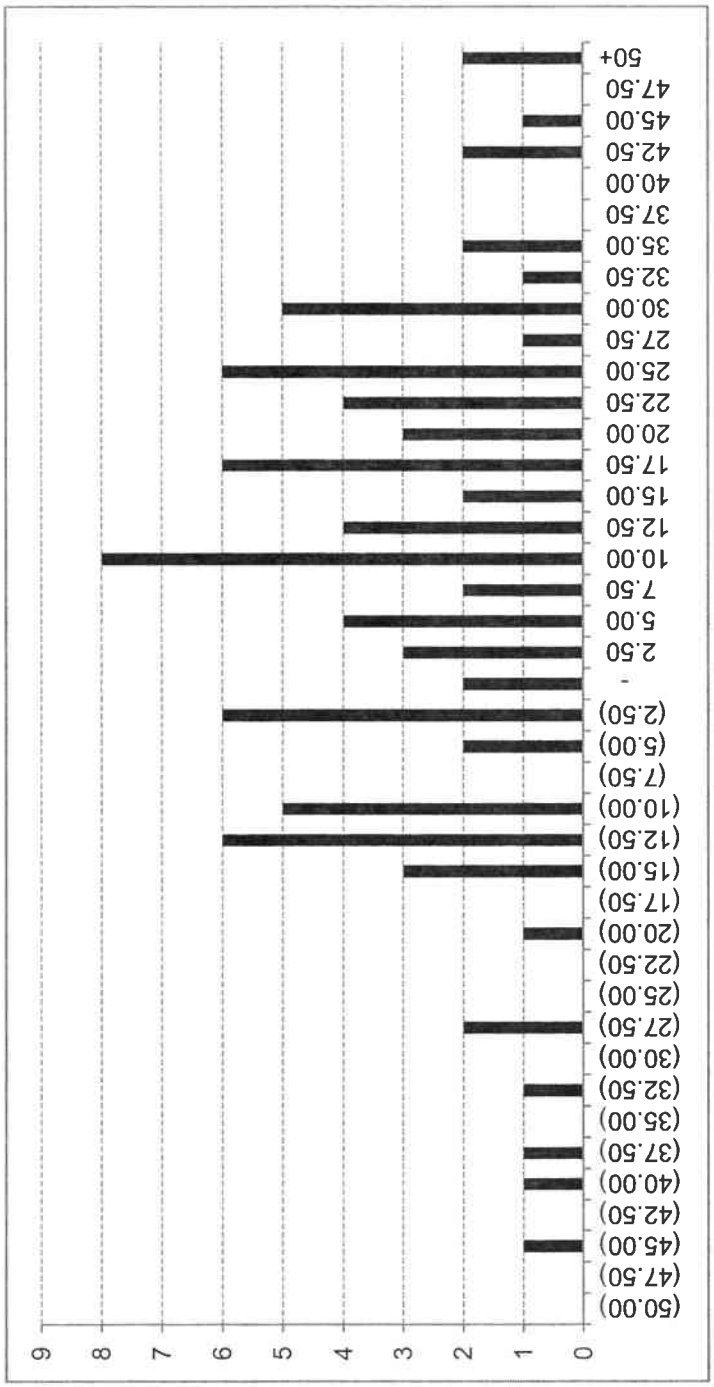
Frequency Distribution of Observed Market Returns, 1926 - 2012



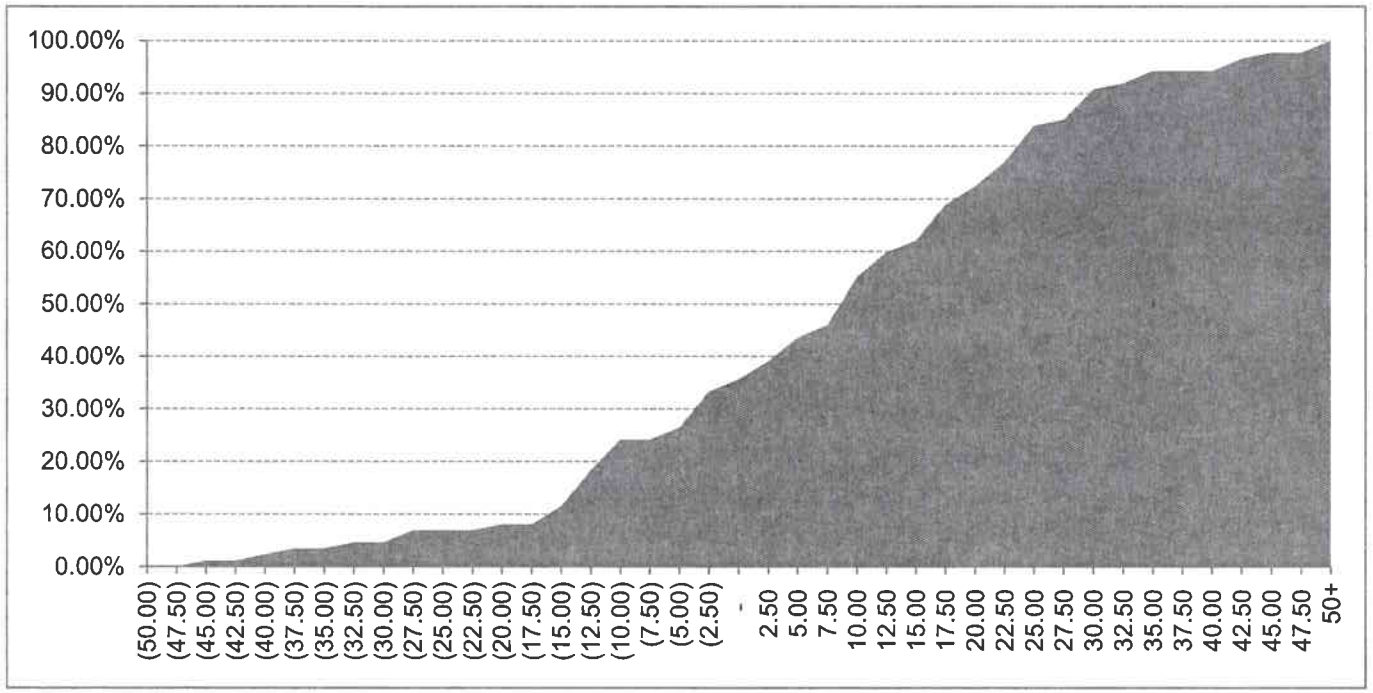
Source: Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 182-183.

Frequency Distribution of Market Risk Premium, 1926 - 2012



Source: Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook; Table A-1, at 142-146

Cumulative Probability of Market Risk Premia, 1926 - 2012



Source: Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook; Table A-1, at 142-146

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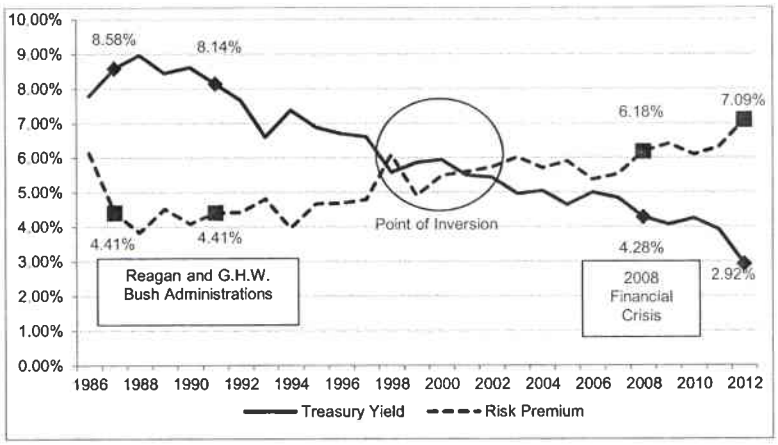
Analysis Using Mr. Gorman's Equity Risk Premium Data

Year	Authorized Electric Returns	30-Year Treasury Yield	Indicated Risk Premium
1986	13.93%	7.80%	6.13%
1987	12.99%	8.58%	4.41%
1988	12.79%	8.96%	3.83%
1989	12.97%	8.45%	4.52%
1990	12.70%	8.61%	4.09%
1991	12.55%	8.14%	4.41%
1992	12.09%	7.67%	4.42%
1993	11.41%	6.60%	4.81%
1994	11.34%	7.37%	3.97%
1995	11.55%	6.88%	4.67%
1996	11.39%	6.70%	4.69%
1997	11.40%	6.61%	4.79%
1998	11.66%	5.58%	6.08%
1999	10.77%	5.87%	4.90%
2000	11.43%	5.94%	5.49%
2001	11.09%	5.49%	5.60%
2002	11.16%	5.43%	5.73%
2003	10.97%	4.96%	6.01%
2004	10.75%	5.05%	5.70%
2005	10.54%	4.65%	5.89%
2006	10.36%	4.99%	5.37%
2007	10.36%	4.83%	5.53%
2008	10.46%	4.28%	6.18%
2009	10.48%	4.07%	6.41%
2010	10.34%	4.25%	6.09%
2011	10.22%	3.91%	6.31%
2012	10.01%	2.92%	7.09%
Average	11.40%	6.10%	5.30%

Source: Exhibit MPG-11

Correlation: -0.87



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.86779378
R Square	0.75306604
Adjusted R Square	0.74318868
Standard Error	0.00436739
Observations	27

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.001454239	0.001454239	76.24164237	4.59555E-09
Residual	25	0.000476852	1.90741E-05		
Total	26	0.001931091			

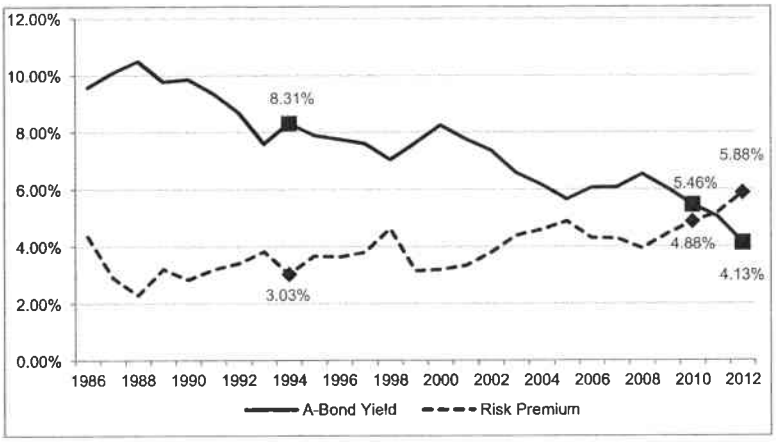
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.08021835	0.003227031	24.85824788	3.79118E-19	0.073572151	0.0868645	0.07357215	0.08686454
30-Year Treasury Yield	-0.446323	0.051115566	-8.731646029	4.59555E-09	-0.551597513	-0.3410486	-0.55159751	-0.34104855

Analysis Using Mr. Gorman's Equity Risk Premium Data

Year	Authorized Electric Returns	Average A Rated Utility Bond Yield	Indicated Risk Premium
1986	13.93%	9.58%	4.35%
1987	12.99%	10.10%	2.89%
1988	12.79%	10.49%	2.30%
1989	12.97%	9.77%	3.20%
1990	12.70%	9.86%	2.84%
1991	12.55%	9.36%	3.19%
1992	12.09%	8.69%	3.40%
1993	11.41%	7.59%	3.82%
1994	11.34%	8.31%	3.03%
1995	11.55%	7.89%	3.66%
1996	11.39%	7.75%	3.64%
1997	11.40%	7.60%	3.80%
1998	11.66%	7.04%	4.62%
1999	10.77%	7.62%	3.15%
2000	11.43%	8.24%	3.19%
2001	11.09%	7.76%	3.33%
2002	11.16%	7.37%	3.79%
2003	10.97%	6.58%	4.39%
2004	10.75%	6.16%	4.59%
2005	10.54%	5.65%	4.89%
2006	10.36%	6.07%	4.29%
2007	10.36%	6.07%	4.29%
2008	10.46%	6.53%	3.93%
2009	10.48%	6.04%	4.44%
2010	10.34%	5.46%	4.88%
2011	10.22%	5.04%	5.18%
2012	10.01%	4.13%	5.88%
Average	11.40%	7.51%	3.89%

Source: Exhibit MPG-12

Correlation: -0.88



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.87654832
R Square	0.76833696
Adjusted R Square	0.75907044
Standard Error	0.00405969
Observations	27

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.001366534	0.001366534	82.91535728	2.05036E-09
Residual	25	0.000412027	1.64811E-05		
Total	26	0.001778561			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.07154797	0.00367266	19.48124014	1.25587E-16	0.063983984	0.079112	0.06398398	0.07911195
A Rated Util Bond Yield	-0.435138	0.047786976	-9.105787022	2.05036E-09	-0.533557149	-0.3367189	-0.53355715	-0.33671891

Analysis Using Mr. Gorman's Equity Risk Premium Data

Year	Authorized Electric Returns	Average A Rated Utility Bond Yield	30-Year Treasury Yield	Credit Spread	Indicated Risk Premium
1986	13.93%	9.58%	7.80%	1.78%	6.13%
1987	12.99%	10.10%	8.58%	1.52%	4.41%
1988	12.79%	10.49%	8.96%	1.53%	3.83%
1989	12.97%	9.77%	8.45%	1.32%	4.52%
1990	12.70%	9.86%	8.61%	1.25%	4.09%
1991	12.55%	9.36%	8.14%	1.22%	4.41%
1992	12.09%	8.69%	7.67%	1.02%	4.42%
1993	11.41%	7.59%	6.60%	0.99%	4.81%
1994	11.34%	8.31%	7.37%	0.94%	3.97%
1995	11.55%	7.89%	6.88%	1.01%	4.67%
1996	11.39%	7.75%	6.70%	1.05%	4.69%
1997	11.40%	7.60%	6.61%	0.99%	4.79%
1998	11.66%	7.04%	5.58%	1.46%	6.08%
1999	10.77%	7.62%	5.87%	1.75%	4.90%
2000	11.43%	8.24%	5.94%	2.30%	5.49%
2001	11.09%	7.76%	5.49%	2.27%	5.60%
2002	11.16%	7.37%	5.43%	1.94%	5.73%
2003	10.97%	6.58%	4.96%	1.62%	6.01%
2004	10.75%	6.16%	5.05%	1.11%	5.70%
2005	10.54%	5.65%	4.65%	1.00%	5.89%
2006	10.36%	6.07%	4.99%	1.08%	5.37%
2007	10.36%	6.07%	4.83%	1.24%	5.53%
2008	10.46%	6.53%	4.28%	2.25%	6.18%
2009	10.48%	6.04%	4.07%	1.97%	6.41%
2010	10.34%	5.46%	4.25%	1.21%	6.09%
2011	10.22%	5.04%	3.91%	1.13%	6.31%
2012	10.01%	4.13%	2.92%	1.21%	7.09%
Average	11.40%	7.51%	6.10%	1.41%	5.30%

Source: Exhibit MPG-11 and Exhibit MPG-12

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.89058969
R Square	0.79314999
Adjusted R Square	0.77591249
Standard Error	0.00407966
Observations	27

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	0.001531644	0.000765822	46.01305079	6.13573E-09
Residual	24	0.000399446	1.66436E-05		
Total	26	0.001931091			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.07351604	0.004329614	16.97981311	7.09138E-15	0.064580155	0.0824519	0.06458016	0.08245192
30-Year Treasury Yield	-0.4306643	0.048296898	-8.917017212	4.38796E-09	-0.530344166	-0.3309844	-0.53034417	-0.33098437
Credit Spread	0.40642149	0.188457542	2.1565679	0.041273957	0.017464236	0.7953787	0.01746424	0.79537873

Analysis Using Mr. Gorman's Equity Risk Premium Data

AREG RiskPrem with T30yr
/METHOD = PW.

Autoregression

Notes

Output Created		02-AUG-2013 15:19:33
Comments		
Input	Active Dataset	DataSet0
	Filter	<none>
	Weight	<none>
	Split File	<none>
	N of Rows in Working Data File	27
Missing Value Handling	Definition of Missing	User-defined missing values are treated as missing.
	Cases Used	Cases with missing values that successively occur at the beginning or end of the series are skipped. All other cases may not contain any missing value.
Syntax		AREG RiskPrem with T30yr /METHOD = PW.
Resources	Processor Time	00:00:00.02
	Elapsed Time	00:00:00.02
Use	From	First observation
	To	Last observation
Predict	From	First observation following the use period
	To	Last observation
Time Series Settings (TSET)	Amount of Output	PRINT = DEFAULT
	Saving New Variables	NEWVAR = CURRENT
	Maximum Number of Lags in Autocorrelation or Partial Autocorrelation Plots	MXAUTO = 16
	Maximum Number of Lags in Cross-Correlation Plots	MXCROSS = 7
	Maximum Number of New Variables Generated Per Procedure	MXNEWVAR = 60
	Maximum Number of New Cases Per Procedure	MXPREDICT = 1000
	Treatment of User-Missing Values	MISSING = EXCLUDE
	Confidence Interval Percentage Value	CIN = 95
	Tolerance for Entering Variables in Regression Equations	TOLER = .0001
	Maximum Iterative Parameter Change	CNVERGE = .001
	Method of Calculating Std. Errors for Autocorrelations	ACFSE = IND
	Length of Seasonal Period	Unspecified
	Variable Whose Values Label Observations in Plots	Unspecified
	Equations Include	CONSTANT
Variables Created or Modified	FIT#1	Fit for RiskPrem from AREG, MOD_4
	ERR#1	Error for RiskPrem from AREG, MOD_4
	LCL#1	95% LCL for RiskPrem from AREG, MOD_4
	UCL#1	95% UCL for RiskPrem from AREG, MOD_4
	SEP#1	SE of Fit for RiskPrem from AREG, MOD_4

Analysis Using Mr. Gorman's Equity Risk Premium Data

[DataSet0]

Model Description

Model Name		MOD_4
Dependent Series		RiskPrem (Y)
Independent Series	1	T30yr (X)
Constant		Included
AR		1

Applying the model specifications from MOD_4

Iteration Termination Criteria

Maximum Parameter Change Less Than	.001
Number of Iterations Equal to	10

Case Processing Summary

Series Length		27
Number of Cases Skipped Due to Missing Values	At the Beginning of the Series	0
	At the End of the Series	0
Number of Cases with Missing Values within the Series		0
Number of Forecasted Cases		0
Number of New Cases Added to the Current Working File		0

Requested Initial Configuration

Rho (AR1)		AUTO
Regression Coefficients	T30yr (X)	AUTO[a]
Constant		AUTO[a]

a. The prior parameter value is invalid and is reset to 0.1.

Analysis Using Mr. Gorman's Equity Risk Premium Data

Iteration 0

Autocorrelation Coefficient

Rho (AR1)	Std. Error
0	.004

The Prais-Winsten estimation method is used.

Model Fit Summary

R	R Square	Adjusted R Square	Std. Error of the Estimate	Durbin-Watson
.868	.753	.743	.004	1.198

The Prais-Winsten estimation method is used.

ANOVA

	Sum of Squares	df	Mean Square
Regression	.001	1	.001
Residual	.000	25	.000

The Prais-Winsten estimation method is used.

Regression Coefficients

	Unstandardized Coefficients		Standardized Coefficients		
	B	Std. Error	Beta	t	Sig.
T30yr (X)	-.446	.051	-.868	-8.732	.000
(Constant)	.080	.003		24.858	.000

The Prais-Winsten estimation method is used.

Iteration History

	Rho (AR1)		Durbin-Watson	Mean Squared Errors
	Value	Std. Error		
0	.121	.203	1.431	.000
1	.129	.202	1.446	.000
2[a]	.129	.202	1.447	.000

The Prais-Winsten estimation method is used.

a. The estimation terminated at this iteration, because all the parameter estimates changed by less than .001.

Analysis Using Mr. Gorman's Equity Risk Premium Data

Final Iteration 2

Autocorrelation Coefficient

Rho (AR1)	Std. Error
.129	.202

The Prais-Winsten estimation method is used.

Model Fit Summary

R	R Square	Adjusted R Square	Std. Error of the Estimate	Durbin-Watson
.847	.717	.694	.004	1.447

The Prais-Winsten estimation method is used.

ANOVA

	Sum of Squares	df	Mean Square
Regression	.001	1	.001
Residual	.000	24	.000

The Prais-Winsten estimation method is used.

Regression Coefficients

	Unstandardized Coefficients		Standardized Coefficients		
	B	Std. Error	Beta	t	Sig.
T30yr (X)	-.452	.058	-.847	-7.801	.000
(Constant)	.081	.004		22.054	.000

The Prais-Winsten estimation method is used.

AREG RiskPrem2 with AUtilityBondYield
/METHOD = PW.

Analysis Using Mr. Gorman's Equity Risk Premium Data

Autoregression

Notes

Output Created		02-AUG-2013 15:21:05
Comments		
Input	Active Dataset	DataSet0
	Filter	<none>
	Weight	<none>
	Split File	<none>
	N of Rows in Working Data File	27
Missing Value Handling	Definition of Missing	User-defined missing values are treated as missing.
	Cases Used	Cases with missing values that successively occur at the beginning or end of the series are skipped. All other cases may not contain any missing value.
Syntax		AREG RiskPrem2 with AUtilityBondYield /METHOD = PW.
Resources	Processor Time	00:00:00.02
	Elapsed Time	00:00:00.01
Use	From	First observation
	To	Last observation
Predict	From	First observation following the use period
	To	Last observation
Time Series Settings (TSET)	Amount of Output	PRINT = DEFAULT
	Saving New Variables	NEWVAR = CURRENT
	Maximum Number of Lags in Autocorrelation or Partial Autocorrelation Plots	MXAUTO = 16
	Maximum Number of Lags in Cross-Correlation Plots	MXCROSS = 7
	Maximum Number of New Variables Generated Per Procedure	MXNEWVAR = 60
	Maximum Number of New Cases Per Procedure	MXPREDICT = 1000
	Treatment of User-Missing Values	MISSING = EXCLUDE
	Confidence Interval Percentage Value	CIN = 95
	Tolerance for Entering Variables in Regression Equations	TOLER = .0001
	Maximum Iterative Parameter Change	CNVERGE = .001
	Method of Calculating Std. Errors for Autocorrelations	ACFSE = IND
	Length of Seasonal Period	Unspecified
	Variable Whose Values Label Observations in Plots	Unspecified
	Equations Include	CONSTANT
Variables Created or Modified	FIT#1	Fit for RiskPrem2 from AREG, MOD_5
	ERR#1	Error for RiskPrem2 from AREG, MOD_5
	LCL#1	95% LCL for RiskPrem2 from AREG, MOD_5
	UCL#1	95% UCL for RiskPrem2 from AREG, MOD_5
	SEP#1	SE of Fit for RiskPrem2 from AREG, MOD_5

Analysis Using Mr. Gorman's Equity Risk Premium Data

[DataSet0]

Model Description

Model Name		MOD_5
Dependent Series		RiskPrem(Y2)
Independent Series	1	AUByield(X2)
Constant		Included
AR		1

Applying the model specifications from MOD_5

Iteration Termination Criteria

Maximum Parameter Change Less Than	.001
Number of Iterations Equal to	10

Case Processing Summary

Series Length		27
Number of Cases Skipped Due to Missing Values	At the Beginning of the Series	0
	At the End of the Series	0
Number of Cases with Missing Values within the Series		0
Number of Forecasted Cases		0
Number of New Cases Added to the Current Working File		0

Requested Initial Configuration

Rho (AR1)		AUTO
Regression Coefficients	AUByield(X2)	AUTO[a]
Constant		AUTO[a]

a. The prior parameter value is invalid and is reset to 0.1.

Analysis Using Mr. Gorman's Equity Risk Premium Data

Iteration 0

Autocorrelation Coefficient

Rho (AR1)	Std. Error
0	.004

The Prais-Winsten estimation method is used.

Model Fit Summary

R	R Square	Adjusted R Square	Std. Error of the Estimate	Durbin-Watson
.877	.768	.759	.004	1.241

The Prais-Winsten estimation method is used.

ANOVA

	Sum of Squares	df	Mean Square
Regression	.001	1	.001
Residual	.000	25	.000

The Prais-Winsten estimation method is used.

Regression Coefficients

	Unstandardized Coefficients		Standardized Coefficients	t	Sig.
	B	Std. Error	Beta		
AUByield(X2)	-.435	.048	-.877	-9.106	.000
(Constant)	.072	.004		19.481	.000

The Prais-Winsten estimation method is used.

Analysis Using Mr. Gorman's Equity Risk Premium Data

Iteration History

	Rho (AR1)		Durbin-Watson	Mean Squared Errors
	Value	Std. Error		
0	.120	.203	1.446	.000
1	.129	.202	1.462	.000
2[a]	.130	.202	1.464	.000

The Prais-Winsten estimation method is used.

a. The estimation terminated at this iteration, because all the parameter estimates changed by less than .001.

Analysis Using Mr. Gorman's Equity Risk Premium Data

Final Iteration 2

Autocorrelation Coefficient

Rho (AR1)	Std. Error
.130	.202

The Prais-Winsten estimation method is used.

Model Fit Summary

R	R Square	Adjusted R Square	Std. Error of the Estimate	Durbin-Watson
.858	.736	.714	.004	1.464

The Prais-Winsten estimation method is used.

ANOVA

	Sum of Squares	df	Mean Square
Regression	.001	1	.001
Residual	.000	24	.000

The Prais-Winsten estimation method is used.

Regression Coefficients

	Unstandardized Coefficients		Standardized Coefficients		
	B	Std. Error	Beta	t	Sig.
AUByield(X2)	-.441	.054	-.858	-8.174	.000
(Constant)	.072	.004		17.376	.000

The Prais-Winsten estimation method is used.

```
AREG RiskPrem3 with CreditSpread,T30yr
/METHOD = PW.
```

Analysis Using Mr. Gorman's Equity Risk Premium Data

Autoregression

Notes

Output Created		02-AUG-2013 15:22:10
Comments		
Input	Active Dataset	DataSet0
	Filter	<none>
	Weight	<none>
	Split File	<none>
	N of Rows in Working Data File	27
Missing Value Handling	Definition of Missing	User-defined missing values are treated as missing.
	Cases Used	Cases with missing values that successively occur at the beginning or end of the series are skipped. All other cases may not contain any missing value.
Syntax		AREG RiskPrem3 with CreditSpread,T30yr /METHOD = PW.
Resources	Processor Time	00:00:00.03
	Elapsed Time	00:00:00.02
Use	From	First observation
	To	Last observation
Predict	From	First observation following the use period
	To	Last observation
Time Series Settings (TSET)	Amount of Output	PRINT = DEFAULT
	Saving New Variables	NEWVAR = CURRENT
	Maximum Number of Lags in Autocorrelation or Partial Autocorrelation Plots	MXAUTO = 16
	Maximum Number of Lags in Cross-Correlation Plots	MXCROSS = 7
	Maximum Number of New Variables Generated Per Procedure	MXNEWVAR = 60
	Maximum Number of New Cases Per Procedure	MXPREDICT = 1000
	Treatment of User-Missing Values	MISSING = EXCLUDE
	Confidence Interval Percentage Value	CIN = 95
	Tolerance for Entering Variables in Regression Equations	TOLER = .0001
	Maximum Iterative Parameter Change	CNVERGE = .001
	Method of Calculating Std. Errors for Autocorrelations	ACFSE = IND
	Length of Seasonal Period	Unspecified
	Variable Whose Values Label Observations in Plots	Unspecified
	Equations Include	CONSTANT
Variables Created or Modified	FIT#1	Fit for RiskPrem3 from AREG, MOD_6
	ERR#1	Error for RiskPrem3 from AREG, MOD_6
	LCL#1	95% LCL for RiskPrem3 from AREG, MOD_6
	UCL#1	95% UCL for RiskPrem3 from AREG, MOD_6
	SEP#1	SE of Fit for RiskPrem3 from AREG, MOD_6

Analysis Using Mr. Gorman's Equity Risk Premium Data

[DataSet0]

Model Description

Model Name		MOD_6
Dependent Series		RiskPrem(Y3)
Independent Series	1	CreditSpread(X3)
	2	T30yr (X)
Constant		Included
AR		1

Applying the model specifications from MOD_6

Iteration Termination Criteria

Maximum Parameter Change Less Than	.001
Number of Iterations Equal to	10

Case Processing Summary

Series Length		27
Number of Cases Skipped Due to Missing Values	At the Beginning of the Series	0
	At the End of the Series	0
Number of Cases with Missing Values within the Series		0
Number of Forecasted Cases		0
Number of New Cases Added to the Current Working File		0

Requested Initial Configuration

Rho (AR1)		AUTO
Regression Coefficients	CreditSpread(X3)	AUTO[a]
	T30yr (X)	AUTO[a]
Constant		AUTO[a]

a. The prior parameter value is invalid and is reset to 0.1.

Analysis Using Mr. Gorman's Equity Risk Premium Data

Iteration 0

Autocorrelation Coefficient

Rho (AR1)	Std. Error
0	.004

The Prais-Winsten estimation method is used.

Model Fit Summary

R	R Square	Adjusted R Square	Std. Error of the Estimate	Durbin-Watson
.891	.793	.776	.004	1.289

The Prais-Winsten estimation method is used.

ANOVA

	Sum of Squares	df	Mean Square
Regression	.002	2	.001
Residual	.000	24	.000

The Prais-Winsten estimation method is used.

Regression Coefficients

	Unstandardized Coefficients		Standardized Coefficients		
	B	Std. Error	Beta	t	Sig.
CreditSpread(X3)	.406	.188	.203	2.157	.041
T30yr (X)	-.431	.048	-.837	-8.917	.000
(Constant)	.074	.004		16.980	.000

The Prais-Winsten estimation method is used.

Iteration History

	Rho (AR1)		Durbin-Watson	Mean Squared Errors
	Value	Std. Error		
0	.073	.208	1.416	.000
1	.080	.208	1.428	.000
2[a]	.081	.208	1.429	.000

The Prais-Winsten estimation method is used.

a. The estimation terminated at this iteration, because all the parameter estimates changed by less than .001.

Analysis Using Mr. Gorman's Equity Risk Premium Data

Final Iteration 2

Autocorrelation Coefficient

Rho (AR1)	Std. Error
.081	.208

The Prais-Winsten estimation method is used.

Model Fit Summary

R	R Square	Adjusted R Square	Std. Error of the Estimate	Durbin-Watson
.879	.773	.744	.004	1.429

The Prais-Winsten estimation method is used.

ANOVA

	Sum of Squares	df	Mean Square
Regression	.001	2	.001
Residual	.000	23	.000

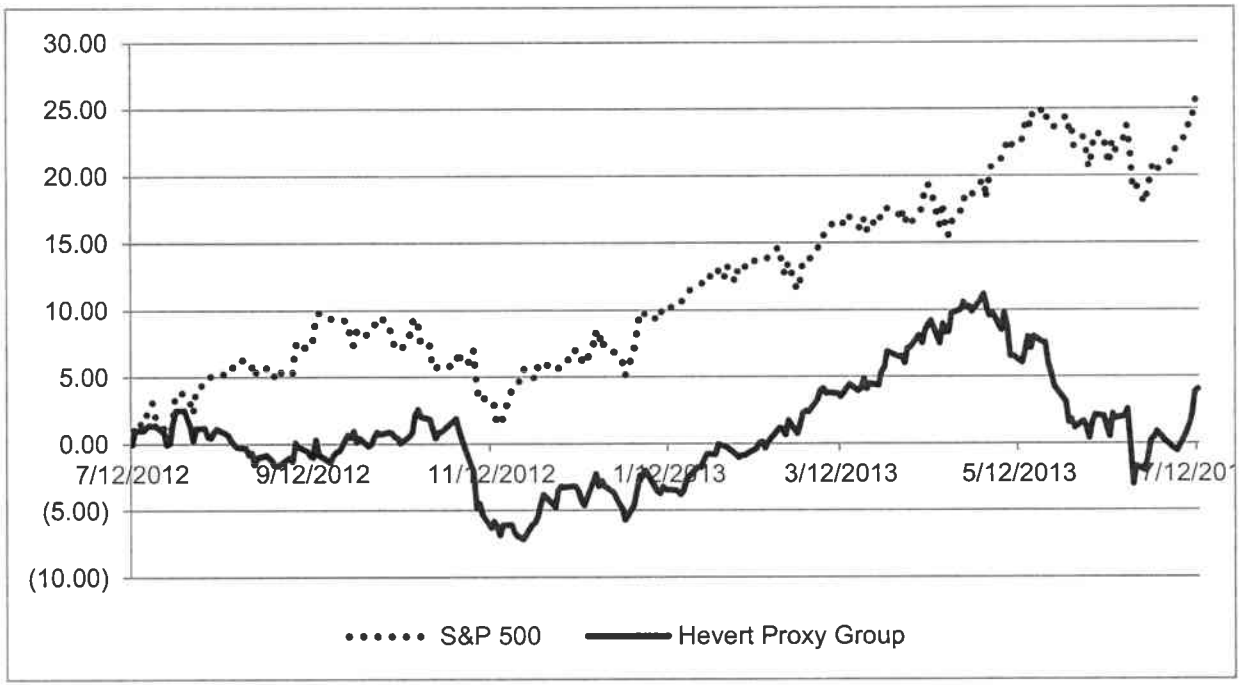
The Prais-Winsten estimation method is used.

Regression Coefficients

	Unstandardized Coefficients		Standardized Coefficients	t	Sig
	B	Std. Error	Beta		
CreditSpread(X3)	.416	.202	.207	2.061	.051
T30yr (X)	-.434	.053	-.826	-8.235	.000
(Constant)	.074	.005		15.759	.000

The Prais-Winsten estimation method is used.

Relative Price Performance



Source: SNL Financial

DOCKET NO. 130040-EI
EXHIBIT NO. ____ (RBH-2)
WITNESS: HEVERT
DOCUMENT NO. 19
PAGE 1 OF 1
FILED: 08/08/2013

Proxy Group Comparison

Companies	Ticker	Hevert Proxy Group	Baudino Proxy Group	Woolridge Proxy Group
ALLETE, Inc.	ALE	[1]		√
Alliant Energy Corporation	LNT	[1]		√
Ameren Corporation	AEE	[1]		√
American Electric Power Company	AEP	√	√	√
Avista Corporation	AVA	[1]		√
Black Hills Corporation	BKH	[1]	√	√
Cleco Corporation	CNL	√	√	√
CMS Energy Corporation	CMS	[1]	√	√
Consolidated Edison, Inc.	ED	[1], [2]	√	√
Dominion Resources, Inc.	D	[1]	√	√
DTE Energy Corporation	DTE	[1]		√
Duke Energy Corporation	DUK	[3]		√
Edison International	EIX	[4]		√
Empire District Electric Company	EDE	√		
First Energy Corporation	FE	[1], [2]		√
Great Plains Energy Inc.	GXP	√	√	√
Hawaiian Electric Industries, Inc.	HE	[5]	√	√
IDACORP, Inc.	IDA	√		√
MGE Energy, Inc.	MGEE	[1]		√
NextEra Energy, Inc.	NEE	[4], [5]		√
Northeast Utilities	NU	[1]		√
NorthWestern Corporation	NWE	[1], [4], [5]		√
Otter Tail Corporation	OTTR	√	√	
Pepco Holdings, Inc.	POM	[2]	√	√
PG&E Corporation	PCG	[1], [5]		√
Pinnacle West Capital Corporation	PNW	√	√	√
PNM Resources	PNM	√		√
Portland General Electric Co.	POR	√		√
PPL Corporation	PPL	[4]		√
SCANA Corporation	SCG	[1]	√	√
Southern Company	SO	√		√
UIL Holdings Corporation	UIL	[1], [2]	√	√
UNS Energy Corporation	UNS	[6]	√	√
Westar Energy, Inc.	WR	√	√	√
Wisconsin Energy Corporation	WEC	[1]	√	√
Xcel Energy, Inc.	XEL	[1]		√

√ Included in proxy group
[1] Removed for having less than 90.00% of regulated net income from electric operations
[2] Removed for having no regulated generation
[3] Removed for being party to a merger or significant transaction
[4] Removed for having less than 60.00% of total net income from regulated operations
[5] Removed for having less than 10.00% of generation from coal-fired generation
[6] Removed for below investment grade rating (while UNS is not rated by S&P, Tucson Electric Power Co. has an S&P long-term issuer rating of BB+)

Growth Rate Regression Analysis

Company	Ticker	PE Ratio	Growth Rate	5-Year Projected Growth Rate	Growth Rate
Ameren Corp.	AEE	16.50	-0.50%	1.50%	-0.50%
Amer. Elec. Power	AEP	14.60	4.50%	4.00%	4.00%
ALLETE	ALE	17.60	7.00%	3.50%	4.00%
Avista Corp.	AVA	18.80	4.00%	4.50%	3.00%
Black Hills	BKH	20.50	11.50%	2.50%	3.00%
CMS Energy Corp.	CMS	16.30	5.50%	8.00%	5.50%
Cleco Corp.	CNL	18.00	5.50%	10.00%	5.00%
CenterPoint Energy	CNP	18.50	4.50%	4.00%	5.50%
Dominion Resources	D	18.90	6.00%	5.50%	4.50%
DTE Energy	DTE	16.30	4.00%	5.50%	4.00%
Duke Energy	DUK	17.80	4.00%	2.00%	3.00%
Consol. Edison	ED	15.70	2.50%	1.50%	3.50%
Empire Dist. Elec.	EDE	15.60	5.00%	3.50%	2.50%
El Paso Electric	EE	15.30	3.00%	NMF	5.00%
Edison Int'l	EIX	10.40	2.50%	5.50%	4.50%
Entergy Corp.	ETR	14.50	-3.50%	0.50%	3.00%
Exelon Corp.	EXC	17.10	-2.50%	-6.50%	5.50%
FirstEnergy Corp.	FE	15.80	3.50%	Nil	2.50%
G't Plains Energy	GXP	14.10	6.50%	6.00%	2.50%
Hawaiian Elec.	HE	16.70	5.50%	2.00%	4.50%
IDACORP, Inc.	IDA	15.20	2.00%	7.00%	4.50%
ITC Holdings	ITC	21.90	15.50%	9.50%	11.50%
Alliant Energy	LNT	14.90	5.00%	4.50%	4.00%
MGE Energy	MGEE	17.60	4.50%	3.50%	5.00%
NextEra Energy	NEE	16.70	5.00%	8.50%	6.00%
Northeast Utilities	NU	17.60	8.00%	8.00%	6.00%
NV Energy Inc.	NVE	16.00	8.00%	12.00%	3.50%
NorthWestern Corp.	NWE	17.00	3.00%	4.00%	4.50%
OGE Energy	OGE	19.20	5.00%	5.50%	6.50%
Otter Tail Corp.	OTTR	20.00	21.50%	1.50%	2.00%
PG&E Corp.	PCG	30.10	4.00%	2.50%	3.00%
Public Serv. Enterprise	PEG	17.00	-2.50%	1.50%	4.00%
PNM Resources	PNM	17.90	12.00%	12.50%	4.00%
Pinnacle West Capital	PNW	16.50	5.00%	2.00%	3.50%
Pepco Holdings	POM	19.10	6.00%	1.00%	2.00%
Portland General	POR	16.80	3.50%	3.50%	3.50%
PPL Corp.	PPL	14.80	Nil	2.00%	5.00%
SCANA Corp.	SCG	15.80	4.50%	2.50%	5.50%
Southern Co.	SO	17.10	4.50%	3.50%	4.00%
Sempra Energy	SRE	18.60	4.50%	7.50%	4.50%
TECO Energy	TE	19.60	3.50%	2.00%	2.50%
Integrys Energy	TEG	14.10	3.50%	0.50%	3.50%
UIL Holdings	UIL	18.60	4.00%	Nil	4.50%
UNS Energy	UNS	19.70	6.50%	5.50%	5.50%
Vectren Corp.	VVC	16.70	6.50%	2.50%	4.00%
Wisconsin Energy	WEC	17.00	5.50%	12.00%	3.50%
Westar Energy	WR	14.00	6.00%	3.00%	5.00%
Xcel Energy Inc.	XEL	16.60	4.50%	4.50%	4.50%

Notes:
Source: Value Line reports, as of July 12, 2013

Growth Rate Regression Analysis

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.320341
R Square	0.102618
Adjusted R Square	0.082676
Standard Error	2.666817
Observations	47

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	36.597014	36.597014	5.145873	0.028148
Residual	45	320.036178	7.111915		
Total	46	356.633191			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	16.136349	0.623060	25.898557	0.000000	14.881442	17.391255	14.881442	17.391255
Proj Earnings Growth Rate	21.849102	9.631724	2.268452	0.028148	2.449813	41.248391	2.449813	41.248391

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.019691
R Square	0.000388
Adjusted R Square	-0.022859
Standard Error	2.872317
Observations	45

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.137611	0.137611	0.016680	0.897841
Residual	43	354.758834	8.250205		
Total	44	354.896444			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	17.162236	0.683920	25.093909	0.000000	15.782979	18.541492	15.782979	18.541492
Proj Dividend Growth Rate	1.581328	12.244139	0.129150	0.897841	-23.111331	26.273987	-23.111331	26.273987

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.093024
R Square	0.008653
Adjusted R Square	-0.012898
Standard Error	2.794903
Observations	48

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3.136571	3.136571	0.401533	0.529437
Residual	46	359.328220	7.811483		
Total	47	362.464792			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	16.545259	1.093920	15.124745	0.000000	14.343312	18.747205	14.343312	18.747205
Proj Book Value Rate	15.463787	24.403662	0.633667	0.529437	-33.658238	64.585811	-33.658238	64.585811

Mr. Baudino's Exhibit RAB-9 Adjusted

AS FILED:

COMPANY	TICKER	Value Line DPS	Value Line EPS	Value Line B x R	Zacks	Thomson Financial
American Electric Power Co.	AEP	4.00%	4.50%	4.00%	3.38%	3.84%
Black Hills Corporation	BKH	2.50%	11.50%	4.00%	6.00%	6.00%
Cleco Corp.	CNL	10.00%	5.50%	4.50%	8.00%	8.00%
CMS Energy Corporation	CMS	8.00%	5.50%	5.00%	5.85%	5.90%
Consolidated Edison, Inc.	ED	1.50%	2.50%	3.50%	3.27%	2.27%
Dominion Resources, Inc.	D	5.50%	6.00%	5.00%	4.63%	7.27%
Great Plains Energy Incorporated	GXP	6.00%	6.50%	3.00%	5.07%	6.26%
Hawaiian Electric Industries, Inc.	HE	2.00%	5.50%	2.50%	3.70%	2.40%
OtterTail Corp..	OTTR	1.50%	21.50%	4.00%	6.00%	6.00%
Pepco Holdings, Inc.	POM	1.00%	6.00%	2.50%	6.00%	4.60%
Pinnacle West Capital Gorp.	PNW	3.62%	5.00%	3.50%	4.13%	6.00%
SCANACorporation	SCG	2.50%	4.50%	4.00%	4.65%	4.80%
UIL Holdings Corporation	UIL	0.00%	4.00%	3.00%	6.50%	8.06%
UNS Energy Corp.	UNS	5.50%	6.50%	4.50%	7.95%	8.00%
Westrar Energy, Inc.	WR	3.00%	6.00%	4.50%	5.13%	4.83%
Wisconsin Energy Corporation	WEC	12.00%	5.50%	5.00%	5.20%	4.93%
	Average:	4.29%	5.67%	3.91%	5.34%	5.57%
	Median:	3.31%	5.50%	4.00%	5.17%	5.95%

Method 1	Value Line DPS	Value Line EPS	Zacks	Thomson Financial	Average of All Growth Rates
Dividend Yield	4.00%	4.00%	4.00%	4.00%	4.00%
Growth Rate	4.29%	5.67%	5.34%	5.57%	5.22%
Expected Div Yield	4.09%	4.11%	4.11%	4.11%	4.10%
DCF ROE	8.37%	9.78%	9.45%	9.68%	9.32%
				Midpoint:	9.08%
Method 2					
Dividend Yield	4.00%	4.00%	4.00%	4.00%	4.00%
Growth Rate	3.31%	5.50%	5.17%	5.95%	4.98%
Expected Div Yield	4.07%	4.11%	4.10%	4.12%	4.10%
DCF ROE	7.38%	9.61%	9.27%	10.07%	9.08%
				Midpoint:	8.72%

Mr. Baudino's Exhibit RAB-9 Adjusted

ADJUSTED TO EXCLUDE NEGATIVE REAL GROWTH RATES

COMPANY	TICKER	Value Line DPS	Value Line EPS	Value Line B x R	Zacks	Thomson Financial
American Electric Power Co.	AEP	4.00%	4.50%	4.00%	3.38%	3.84%
Black Hills Corporation	BKH	2.50%	11.50%	4.00%	6.00%	6.00%
Cleco Corp.	CNL	10.00%	5.50%	4.50%	8.00%	8.00%
CMS Energy Corporation	CMS	8.00%	5.50%	5.00%	5.85%	5.90%
Consolidated Edison, Inc.	ED		2.50%	3.50%	3.27%	2.27%
Dominion Resources, Inc.	D	5.50%	6.00%	5.00%	4.63%	7.27%
Great Plains Energy Incorporated	GXP	6.00%	6.50%	3.00%	5.07%	6.26%
Hawaiian Electric Industries, Inc.	HE		5.50%	2.50%	3.70%	2.40%
OtterTail Corp..	OTTR		21.50%	4.00%	6.00%	6.00%
Pepco Holdings, Inc.	POM		6.00%	2.50%	6.00%	4.60%
Pinnacle West Capital Corp.	PNW	3.62%	5.00%	3.50%	4.13%	6.00%
SCANACorporation	SCG	2.50%	4.50%	4.00%	4.65%	4.80%
UIL Holdings Corporation	UIL		4.00%	3.00%	6.50%	8.06%
UNS Energy Corp.	UNS	5.50%	6.50%	4.50%	7.95%	8.00%
Westrar Energy, Inc.	WR	3.00%	6.00%	4.50%	5.13%	4.83%
Wisconsin Energy Corporation	WEC	12.00%	5.50%	5.00%	5.20%	4.93%
	Average:	5.69%	5.67%	3.91%	5.34%	5.57%
	Median:	5.50%	5.50%	4.00%	5.17%	5.95%

Method 1	Value Line DPS	Value Line EPS	Zacks	Thomson Financial	Average of All Growth Rates	
Dividend Yield	4.00%	4.00%	4.00%	4.00%	4.00%	
Growth Rate	5.69%	5.67%	5.34%	5.57%	5.57%	Increase
Expected Div Yield	4.11%	4.11%	4.11%	4.11%	4.11%	From Filed:
DCF ROE	9.81%	9.78%	9.45%	9.68%	9.68%	0.36%
				Midpoint:	9.63%	0.55%
Method 2						
Dividend Yield	4.00%	4.00%	4.00%	4.00%	4.00%	
Growth Rate	5.50%	5.50%	5.17%	5.95%	5.53%	Increase
Expected Div Yield	4.11%	4.11%	4.10%	4.12%	4.11%	From Filed:
DCF ROE	9.61%	9.61%	9.27%	10.07%	9.64%	0.56%
				Midpoint:	9.67%	0.95%

SOURCE: EXHIBIT RAB-9; differences due to rounding.

NOTE: Excludes growth rates below 2.21 percent expected rate of inflation. Inflation rate = 30-year nominal Treasury yield (3.46 percent) less the 30-year TIPS yield (1.25 percent) (30 day average rates as of July 12, 2013.)

Value Line Projected Sustainable Growth And Return On Common Equity

Company	Value Line Return on Common Equity ("R")	Value Line Payout Ratio Ratio	Retention Ratio ("B")	B x R	Value Line Retained to Common Equity	Difference
AEP	10.00%	61.00%	39.00%	3.90%	4.00%	-0.10%
BKH	9.00%	56.00%	44.00%	3.96%	4.00%	-0.04%
CNL	11.00%	57.00%	43.00%	4.73%	4.50%	0.23%
CMS	13.00%	62.00%	38.00%	4.94%	5.00%	-0.06%
ED	9.00%	60.00%	40.00%	3.60%	3.50%	0.10%
D	16.00%	68.00%	32.00%	5.12%	5.00%	0.12%
GXP	8.00%	60.00%	40.00%	3.20%	3.00%	0.20%
HE	9.00%	72.00%	28.00%	2.52%	2.50%	0.02%
OTTR	11.00%	66.00%	34.00%	3.74%	4.00%	-0.26%
POM	8.00%	69.00%	31.00%	2.48%	2.50%	-0.02%
PNW	10.00%	62.00%	38.00%	3.80%	3.50%	0.30%
SCG	9.50%	57.00%	43.00%	4.09%	4.00%	0.09%
UIL	9.00%	68.00%	32.00%	2.88%	3.00%	-0.12%
UNS	11.50%	60.00%	40.00%	4.60%	4.50%	0.10%
WR	9.50%	54.00%	46.00%	4.37%	4.50%	-0.13%
WEC	14.00%	66.00%	34.00%	4.76%	5.00%	-0.24%
AVERAGE:	10.47%	62.38%	37.63%	3.92%	3.91%	0.01%
MEDIAN:	9.75%	61.50%	38.50%	3.93%	4.00%	0.00%

Source: Value Line projections 2016-2018 period, as of July 12, 2013.
Note: Retention Ratio equals 1 - Payout Ratio

Equity Duration Calculation Using Mr. Baudino's DCF Model Data

Company	Ticker	As-Filed 6-Month Average Price	Annual Dividend	Mean Projected Growth Rate	Constant Growth DCF ROE	Solved ROE	Price	Div 1	Div 2	Div 3	Div 4	Div 5	Div 6	Div 7	Div 8	Div 9	Div 10	Div 199	Div 200
American Electric Power Company	AEP	46.71	1.96	3.93%	8.21%	8.21%	($46.71)	$ 2.00	$ 2.08	$ 2.16	$ 2.24	$ 2.33	$ 2.42	$ 2.52	$ 2.62	$ 2.72	$ 2.83	$ 4,124.88	$ 4,286.98
Black Hills Corporation	BKH	43.80	1.52	6.50%	10.08%	10.08%	($43.80)	$ 1.57	$ 1.67	$ 1.78	$ 1.90	$ 2.02	$ 2.15	$ 2.29	$ 2.44	$ 2.60	$ 2.77	$ 408,278.01	$ 434,816.08
Cleco Corporation	CNL	45.13	1.45	7.88%	11.21%	11.20%	($45.13)	$ 1.51	$ 1.62	$ 1.75	$ 1.89	$ 2.04	$ 2.20	$ 2.37	$ 2.56	$ 2.76	$ 2.98	$ 4,964,333.57	$ 5,355,274.84
CMS Energy Corporation	CMS	27.03	1.02	6.31%	10.21%	10.20%	($27.03)	$ 1.05	$ 1.12	$ 1.19	$ 1.26	$ 1.34	$ 1.43	$ 1.52	$ 1.62	$ 1.72	$ 1.83	$ 193,104.88	$ 205,294.62
Consolidated Edison, Inc.	ED	58.87	2.46	2.39%	6.61%	6.61%	($58.87)	$ 2.49	$ 2.55	$ 2.61	$ 2.67	$ 2.74	$ 2.80	$ 2.87	$ 2.94	$ 3.01	$ 3.08	$ 264.78	$ 271.09
Dominion Resources, Inc.	D	56.70	2.25	5.85%	9.94%	9.94%	($56.70)	$ 2.32	$ 2.45	$ 2.60	$ 2.75	$ 2.91	$ 3.08	$ 3.26	$ 3.45	$ 3.65	$ 3.87	$ 179,423.78	$ 189,920.07
Great Plains Energy Inc.	GXP	22.39	0.87	5.96%	9.95%	9.95%	($22.39)	$ 0.89	$ 0.95	$ 1.00	$ 1.06	$ 1.13	$ 1.19	$ 1.26	$ 1.34	$ 1.42	$ 1.50	$ 84,594.96	$ 89,634.71
Hawaiian Electric Industries, Inc.	HE	26.69	1.24	3.40%	8.12%	8.12%	($26.69)	$ 1.26	$ 1.30	$ 1.35	$ 1.39	$ 1.44	$ 1.49	$ 1.54	$ 1.59	$ 1.65	$ 1.70	$ 945.82	$ 977.98
Otter Tail Corporation	OTTR	28.59	1.19	4.50%	8.76%	8.76%	($28.59)	$ 1.22	$ 1.27	$ 1.33	$ 1.39	$ 1.45	$ 1.52	$ 1.59	$ 1.66	$ 1.73	$ 1.81	$ 7,429.59	$ 7,763.93
Pepco Holdings, Inc.	POM	20.68	1.08	4.40%	9.74%	9.74%	($20.68)	$ 1.10	$ 1.15	$ 1.20	$ 1.26	$ 1.31	$ 1.37	$ 1.43	$ 1.49	$ 1.56	$ 1.63	$ 5,566.39	$ 5,811.31
Pinnacle West Capital Corporation	PNW	56.11	2.18	4.69%	8.66%	8.66%	($56.11)	$ 2.23	$ 2.34	$ 2.45	$ 2.56	$ 2.68	$ 2.81	$ 2.94	$ 3.07	$ 3.22	$ 3.37	$ 19,395.18	$ 20,304.33
SCANA Corporation	SCG	49.71	2.03	4.11%	8.28%	8.27%	($49.71)	$ 2.07	$ 2.15	$ 2.24	$ 2.34	$ 2.43	$ 2.53	$ 2.64	$ 2.74	$ 2.86	$ 2.97	$ 6,046.12	$ 6,294.77
UIL Holdings Corporation	UIL	38.81	1.73	4.64%	9.20%	9.19%	($38.81)	$ 1.77	$ 1.85	$ 1.94	$ 2.03	$ 2.12	$ 2.22	$ 2.32	$ 2.43	$ 2.54	$ 2.66	$ 14,049.31	$ 14,701.20
UNS Energy Corporation	UNS	46.92	1.74	6.99%	10.83%	10.82%	($46.92)	$ 1.80	$ 1.93	$ 2.06	$ 2.21	$ 2.36	$ 2.52	$ 2.70	$ 2.89	$ 3.09	$ 3.31	$ 1,157,191.33	$ 1,238,050.07
Westar Energy, Inc.	WR	31.77	1.36	4.74%	9.12%	9.12%	($31.77)	$ 1.39	$ 1.46	$ 1.53	$ 1.60	$ 1.68	$ 1.75	$ 1.84	$ 1.93	$ 2.02	$ 2.11	$ 13,365.97	$ 13,999.51
Wisconsin Energy Corporation	WEC	41.21	1.36	6.91%	10.32%	10.32%	($41.21)	$ 1.41	$ 1.50	$ 1.61	$ 1.72	$ 1.84	$ 1.96	$ 2.10	$ 2.25	$ 2.40	$ 2.57	$ 779,656.96	$ 833,511.77

Duration calculation

Company	Ticker	Equity Duration	Div 1	Div 2	Div 3	Div 4	Div 5	Div 6	Div 7	Div 8	Div 9	Div 10	Div 199	Div 200
American Electric Power Company	AEP	25.22	0.04	0.08	0.11	0.14	0.17	0.19	0.22	0.24	0.26	0.28	0.00	0.00
Black Hills Corporation	BKH	30.41	0.03	0.06	0.09	0.12	0.14	0.17	0.19	0.21	0.22	0.24	0.01	0.01
Cleco Corporation	CNL	32.82	0.03	0.06	0.08	0.11	0.13	0.15	0.17	0.19	0.21	0.23	0.01	0.01
CMS Energy Corporation	CMS	28.14	0.04	0.07	0.10	0.13	0.15	0.18	0.20	0.22	0.24	0.26	0.01	0.01
Consolidated Edison, Inc.	ED	25.14	0.04	0.08	0.11	0.14	0.17	0.19	0.22	0.24	0.26	0.28	0.00	0.00
Dominion Resources, Inc.	D	26.78	0.04	0.07	0.10	0.13	0.16	0.18	0.21	0.23	0.25	0.26	0.00	0.00
Great Plains Energy Inc.	GXP	27.40	0.04	0.07	0.10	0.13	0.16	0.18	0.20	0.22	0.24	0.26	0.00	0.00
Hawaiian Electric Industries, Inc.	HE	22.86	0.04	0.08	0.12	0.15	0.18	0.21	0.23	0.26	0.28	0.29	0.00	0.00
Otter Tail Corporation	OTTR	25.44	0.04	0.08	0.11	0.14	0.17	0.19	0.22	0.24	0.26	0.27	0.00	0.00
Pepco Holdings, Inc.	POM	20.55	0.05	0.09	0.13	0.17	0.20	0.23	0.25	0.27	0.29	0.31	0.00	0.00
Pinnacle West Capital Corporation	PNW	27.20	0.04	0.07	0.10	0.13	0.16	0.18	0.20	0.23	0.24	0.26	0.00	0.00
SCANA Corporation	SCG	25.91	0.04	0.07	0.11	0.14	0.16	0.19	0.21	0.23	0.25	0.27	0.00	0.00
UIL Holdings Corporation	UIL	23.93	0.04	0.08	0.11	0.15	0.18	0.20	0.23	0.25	0.27	0.28	0.00	0.00
UNS Energy Corporation	UNS	28.68	0.03	0.07	0.10	0.12	0.15	0.17	0.20	0.22	0.24	0.25	0.01	0.01
Westar Energy, Inc.	WR	24.84	0.04	0.08	0.11	0.14	0.17	0.20	0.22	0.24	0.26	0.28	0.00	0.00
Wisconsin Energy Corporation	WEC	31.88	0.03	0.06	0.09	0.11	0.14	0.16	0.18	0.20	0.22	0.23	0.01	0.01
	Average:	26.70												
	Median:	26.35												

Notes:

Source: Exhibit RAB-8 and ExhibitRAB-9

Mean projected growth rate excludes Mr. Baudino's Sustainable Growth rate since that rate was not used in his DCF calculations

$$D = \frac{\sum_{t=1}^{T} t \times \frac{CF_t}{(1+r)^t}}{P}$$

Where: t = time period (1 through 200)
CF = Cash Flow (i.e. dividend) at time t
r = ROE
P = Current Stock Price

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Duration of Treasury Bonds at Current Interest Rates

Start Date	7/12/2013	7/12/2013	7/12/2013	
Maturity Date	7/12/2043	7/12/2033	7/12/2018	
Term (years)	30	20	5	
Par	100	100	100	
Interest Rate	3.46%	3.14%	1.28%	(30-day average)
Excel Duration	19.14	15.15	4.88	

Manual calculation (check):

	Cash Flows Period	1	2	3	4	5	6	7	8	9	10	11
	30year Treasury:	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46
	20year Treasury:	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14
	5year Treasury:	1.28	1.28	1.28	1.28	101.28						
Duration	Discounted Value of Cash Flow											
19.14	30year Treasury:	3.34	3.23	3.12	3.02	2.92	2.82	2.72	2.63	2.54	2.46	2.38
15.15	20year Treasury:	3.04	2.95	2.86	2.77	2.69	2.61	2.53	2.45	2.38	2.31	2.23
4.88	5year Treasury:	1.26	1.24	1.23	1.21	95.05						

Notes:
Interest rates based on 30-day average; Source: Bloomberg Professional

$$D = \frac{\sum_{t=1}^{T} t \times \frac{CF_t}{(1+r)^t}}{P}$$

Where: t = time period
CF = cash flow (i.e. coupon) at time t
r = discount rate
P = current price (assumed par)

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Duration of Treasury Bonds at Current Interest Rates

12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	103.46
3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.14	103.14										
2.30	2.22	2.15	2.08	2.01	1.94	1.87	1.81	1.75	1.69	1.64	1.58	1.53	1.48	1.43	1.38	1.33	1.29	37.34
2.17	2.10	2.04	1.97	1.91	1.86	1.80	1.75	55.57										

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Mr. Baudino's Proxy Group
Percent Institutional Ownership

Company	Ticker	Institutional Ownership
American Electric Power Co.	AEP	64.25%
Black Hills Corp	BKH	67.81%
CMS Energy Corp.	CMS	87.02%
Cleco Corp.	CNL	72.40%
Dominion Resources Inc.	D	58.78%
Consolidated Edison Inc.	ED	45.59%
Great Plains Energy	GXP	73.08%
Hawaiian Electric Industries	HE	40.57%
Otter Tail Corp.	OTTR	41.86%
Pinnacle West Capital Corp.	PNW	77.40%
Pepco Holdings Inc.	POM	57.21%
SCANA Corp.	SCG	47.14%
UIL Holdings Corp.	UIL	64.20%
UNS Energy Corp.	UNS	90.66%
Wisconsin Energy Corp.	WEC	68.27%
Westar Energy Inc.	WR	58.97%
	Mean:	63.45%

Source: SNL Financial; data as of July 24, 2013.

DCF Model ROE Estimate Assuming Different Holding Periods and No Terminal Value

Perpetual Holding Period (200 years)

Company	Ticker	As-Filed 6-Month Average Price	Annual Dividend	Mean Projected Growth Rat	Constant Growth DCF ROE	Solved ROE	Price	Div 1	Div 2	Div 3	Div 4	Div 5	Div 6	Div 7	Div 8	Div 9	Div 10	Div 199	Div 200
American Electric Power Company	AEP	46.71	1.96	3.93%	8.21%	8.21%	($46.71)	$ 2.00	$ 2.08	$ 2.16	$ 2.24	$ 2.33	$ 2.42	$ 2.52	$ 2.62	$ 2.72	$ 2.83	$ 4,124.88	$ 4,286.98
Black Hills Corporation	BKH	43.80	1.52	6.50%	10.08%	10.08%	($43.80)	$ 1.57	$ 1.67	$ 1.78	$ 1.90	$ 2.02	$ 2.15	$ 2.29	$ 2.44	$ 2.60	$ 2.77	$ 408,278.01	$ 434,816.08
Cleco Corporation	CNL	45.13	1.45	7.88%	11.21%	11.20%	($45.13)	$ 1.51	$ 1.62	$ 1.75	$ 1.89	$ 2.04	$ 2.20	$ 2.37	$ 2.56	$ 2.76	$ 2.98	$ 4,964,333.57	$ 5,355,274.84
CMS Energy Corporation	CMS	27.03	1.02	6.31%	10.21%	10.20%	($27.03)	$ 1.05	$ 1.12	$ 1.19	$ 1.26	$ 1.34	$ 1.43	$ 1.52	$ 1.62	$ 1.72	$ 1.83	$ 193,104.88	$ 205,294.62
Consolidated Edison, Inc.	ED	58.87	2.46	2.39%	6.61%	6.61%	($58.87)	$ 2.49	$ 2.55	$ 2.61	$ 2.67	$ 2.74	$ 2.80	$ 2.87	$ 2.94	$ 3.01	$ 3.08	$ 264.78	$ 271.09
Dominion Resources, Inc.	D	56.70	2.25	5.85%	9.94%	9.94%	($56.70)	$ 2.32	$ 2.45	$ 2.60	$ 2.75	$ 2.91	$ 3.08	$ 3.26	$ 3.45	$ 3.65	$ 3.87	$ 179,423.78	$ 189,920.07
Great Plains Energy Inc.	GXP	22.39	0.87	5.96%	9.95%	9.95%	($22.39)	$ 0.89	$ 0.95	$ 1.00	$ 1.06	$ 1.13	$ 1.19	$ 1.26	$ 1.34	$ 1.42	$ 1.50	$ 84,594.96	$ 89,634.71
Hawaiian Electric Industries, Inc.	HE	26.69	1.24	3.40%	8.12%	8.12%	($26.69)	$ 1.26	$ 1.30	$ 1.35	$ 1.39	$ 1.44	$ 1.49	$ 1.54	$ 1.59	$ 1.65	$ 1.70	$ 945.82	$ 977.98
Otter Tail Corporation	OTTR	28.59	1.19	4.50%	8.76%	8.76%	($28.59)	$ 1.22	$ 1.27	$ 1.33	$ 1.39	$ 1.45	$ 1.52	$ 1.59	$ 1.66	$ 1.73	$ 1.81	$ 7,429.59	$ 7,763.93
Pepco Holdings, Inc.	POM	20.68	1.08	4.40%	9.74%	9.74%	($20.68)	$ 1.10	$ 1.15	$ 1.20	$ 1.26	$ 1.31	$ 1.37	$ 1.43	$ 1.49	$ 1.56	$ 1.63	$ 5,566.39	$ 5,811.31
Pinnacle West Capital Corporation	PNW	56.11	2.18	4.69%	8.66%	8.66%	($56.11)	$ 2.23	$ 2.34	$ 2.45	$ 2.56	$ 2.68	$ 2.81	$ 2.94	$ 3.07	$ 3.22	$ 3.37	$ 19,395.18	$ 20,304.33
SCANA Corporation	SCG	49.71	2.03	4.11%	8.28%	8.27%	($49.71)	$ 2.07	$ 2.15	$ 2.24	$ 2.34	$ 2.43	$ 2.53	$ 2.64	$ 2.74	$ 2.86	$ 2.97	$ 6,046.12	$ 6,294.77
UIL Holdings Corporation	UIL	38.81	1.73	4.64%	9.20%	9.19%	($38.81)	$ 1.77	$ 1.85	$ 1.94	$ 2.03	$ 2.12	$ 2.22	$ 2.32	$ 2.43	$ 2.54	$ 2.66	$ 14,049.31	$ 14,701.20
UNS Energy Corporation	UNS	46.92	1.74	6.99%	10.83%	10.82%	($46.92)	$ 1.80	$ 1.93	$ 2.06	$ 2.21	$ 2.36	$ 2.52	$ 2.70	$ 2.89	$ 3.09	$ 3.31	$ 1,157,191.33	$ 1,238,050.07
Westar Energy, Inc.	WR	31.77	1.36	4.74%	9.12%	9.12%	($31.77)	$ 1.39	$ 1.46	$ 1.53	$ 1.60	$ 1.68	$ 1.75	$ 1.84	$ 1.93	$ 2.02	$ 2.11	$ 13,365.97	$ 13,999.51
Wisconsin Energy Corporation	WEC	41.21	1.36	6.91%	10.32%	10.32%	($41.21)	$ 1.41	$ 1.50	$ 1.61	$ 1.72	$ 1.84	$ 1.96	$ 2.10	$ 2.25	$ 2.40	$ 2.57	$ 779,656.96	$ 833,511.77
					Mean:	9.32%													
					Median:	9.47%													

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Twenty Year Holding Period

Company	Ticker	6-Month Average Price	Annual Dividend	Mean Projected Growth Rat	Constant Growth DCF ROE	Solved ROE	Price	Div 1	Div 2	Div 3	Div 4	Div 5	Div 6	Div 7	Div 8	Div 9	Div 10	Div 19	Div 20
American Electric Power Company	AEP	46.71	1.96	3.93%	8.21%	2.08%	($46.71)	$ 2.00	$ 2.08	$ 2.16	$ 2.24	$ 2.33	$ 2.42	$ 2.52	$ 2.62	$ 2.72	$ 2.83	$ 4.00	$ 4.16
Black Hills Corporation	BKH	43.80	1.52	6.50%	10.08%	2.76%	($43.80)	$ 1.57	$ 1.67	$ 1.78	$ 1.90	$ 2.02	$ 2.15	$ 2.29	$ 2.44	$ 2.60	$ 2.77	$ 4.88	$ 5.19
Cleco Corporation	CNL	45.13	1.45	7.88%	11.21%	3.35%	($45.13)	$ 1.51	$ 1.62	$ 1.75	$ 1.89	$ 2.04	$ 2.20	$ 2.37	$ 2.56	$ 2.76	$ 2.98	$ 5.89	$ 6.35
CMS Energy Corporation	CMS	27.03	1.02	6.31%	10.21%	3.34%	($27.03)	$ 1.05	$ 1.12	$ 1.19	$ 1.26	$ 1.34	$ 1.43	$ 1.52	$ 1.62	$ 1.72	$ 1.83	$ 3.17	$ 3.37
Consolidated Edison, Inc.	ED	58.87	2.46	2.39%	6.61%	0.59%	($58.87)	$ 2.49	$ 2.55	$ 2.61	$ 2.67	$ 2.74	$ 2.80	$ 2.87	$ 2.94	$ 3.01	$ 3.08	$ 3.80	$ 3.90
Dominion Resources, Inc.	D	56.70	2.25	5.85%	9.94%	3.37%	($56.70)	$ 2.32	$ 2.45	$ 2.60	$ 2.75	$ 2.91	$ 3.08	$ 3.26	$ 3.45	$ 3.65	$ 3.87	$ 6.45	$ 6.83
Great Plains Energy Inc.	GXP	22.39	0.87	5.96%	9.95%	3.25%	($22.39)	$ 0.89	$ 0.95	$ 1.00	$ 1.06	$ 1.13	$ 1.19	$ 1.26	$ 1.34	$ 1.42	$ 1.50	$ 2.53	$ 2.68
Hawaiian Electric Industries, Inc.	HE	26.69	1.24	3.40%	8.12%	2.53%	($26.69)	$ 1.26	$ 1.30	$ 1.35	$ 1.39	$ 1.44	$ 1.49	$ 1.54	$ 1.59	$ 1.65	$ 1.70	$ 2.30	$ 2.38
Otter Tail Corporation	OTTR	28.59	1.19	4.50%	8.76%	2.55%	($28.59)	$ 1.22	$ 1.27	$ 1.33	$ 1.39	$ 1.45	$ 1.52	$ 1.59	$ 1.66	$ 1.73	$ 1.81	$ 2.69	$ 2.81
Pepco Holdings, Inc.	POM	20.68	1.08	4.40%	9.74%	4.62%	($20.68)	$ 1.10	$ 1.15	$ 1.20	$ 1.26	$ 1.31	$ 1.37	$ 1.43	$ 1.49	$ 1.56	$ 1.63	$ 2.40	$ 2.50
Pinnacle West Capital Corporation	PNW	56.11	2.18	4.69%	8.66%	2.08%	($56.11)	$ 2.23	$ 2.34	$ 2.45	$ 2.56	$ 2.68	$ 2.81	$ 2.94	$ 3.07	$ 3.22	$ 3.37	$ 5.09	$ 5.33
SCANA Corporation	SCG	49.71	2.03	4.11%	8.28%	1.99%	($49.71)	$ 2.07	$ 2.15	$ 2.24	$ 2.34	$ 2.43	$ 2.53	$ 2.64	$ 2.74	$ 2.86	$ 2.97	$ 4.28	$ 4.45
UIL Holdings Corporation	UIL	38.81	1.73	4.64%	9.20%	3.30%	($38.81)	$ 1.77	$ 1.85	$ 1.94	$ 2.03	$ 2.12	$ 2.22	$ 2.32	$ 2.43	$ 2.54	$ 2.66	$ 4.00	$ 4.19
UNS Energy Corporation	UNS	46.92	1.74	6.99%	10.83%	3.81%	($46.92)	$ 1.80	$ 1.93	$ 2.06	$ 2.21	$ 2.36	$ 2.52	$ 2.70	$ 2.89	$ 3.09	$ 3.31	$ 6.07	$ 6.50
Westar Energy, Inc.	WR	31.77	1.36	4.74%	9.12%	3.02%	($31.77)	$ 1.39	$ 1.46	$ 1.53	$ 1.60	$ 1.68	$ 1.75	$ 1.84	$ 1.93	$ 2.02	$ 2.11	$ 3.20	$ 3.36
Wisconsin Energy Corporation	WEC	41.21	1.36	6.91%	10.32%	2.70%	($41.21)	$ 1.41	$ 1.50	$ 1.61	$ 1.72	$ 1.84	$ 1.96	$ 2.10	$ 2.25	$ 2.40	$ 2.57	$ 4.68	$ 5.01
					Mean:	2.83%													
					Median:	2.89%													

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Five Year Holding Period

Company	Ticker	6-Month Average Price	Annual Dividend	Mean Projected Growth Rat	Constant Growth DCF ROE	Solved ROE	Price	Div 1	Div 2	Div 3	Div 4	Div 5
American Electric Power Company	AEP	46.71	1.96	3.93%	8.21%	-34.36%	($46.71)	$ 2.00	$ 2.08	$ 2.16	$ 2.24	$ 2.33
Black Hills Corporation	BKH	43.80	1.52	6.50%	10.08%	-36.14%	($43.80)	$ 1.57	$ 1.67	$ 1.78	$ 1.90	$ 2.02
Cleco Corporation	CNL	45.13	1.45	7.88%	11.21%	-36.69%	($45.13)	$ 1.51	$ 1.62	$ 1.75	$ 1.89	$ 2.04
CMS Energy Corporation	CMS	27.03	1.02	6.31%	10.21%	-34.86%	($27.03)	$ 1.05	$ 1.12	$ 1.19	$ 1.26	$ 1.34
Consolidated Edison, Inc.	ED	58.87	2.46	2.39%	6.61%	-35.28%	($58.87)	$ 2.49	$ 2.55	$ 2.61	$ 2.67	$ 2.74
Dominion Resources, Inc.	D	56.70	2.25	5.85%	9.94%	-34.24%	($56.70)	$ 2.32	$ 2.45	$ 2.60	$ 2.75	$ 2.91
Great Plains Energy Inc.	GXP	22.39	0.87	5.96%	9.95%	-34.59%	($22.39)	$ 0.89	$ 0.95	$ 1.00	$ 1.06	$ 1.13
Hawaiian Electric Industries, Inc.	HE	26.69	1.24	3.40%	8.12%	-32.89%	($26.69)	$ 1.26	$ 1.30	$ 1.35	$ 1.39	$ 1.44
Otter Tail Corporation	OTTR	28.59	1.19	4.50%	8.76%	-34.15%	($28.59)	$ 1.22	$ 1.27	$ 1.33	$ 1.39	$ 1.45
Pepco Holdings, Inc.	POM	20.68	1.08	4.40%	9.74%	-30.19%	($20.68)	$ 1.10	$ 1.15	$ 1.20	$ 1.26	$ 1.31
Pinnacle West Capital Corporation	PNW	56.11	2.18	4.69%	8.66%	-35.24%	($56.11)	$ 2.23	$ 2.34	$ 2.45	$ 2.56	$ 2.68
SCANA Corporation	SCG	49.71	2.03	4.11%	8.28%	-34.73%	($49.71)	$ 2.07	$ 2.15	$ 2.24	$ 2.34	$ 2.43
UIL Holdings Corporation	UIL	38.81	1.73	4.64%	9.20%	-32.94%	($38.81)	$ 1.77	$ 1.85	$ 1.94	$ 2.03	$ 2.12
UNS Energy Corporation	UNS	46.92	1.74	6.99%	10.83%	-34.79%	($46.92)	$ 1.80	$ 1.93	$ 2.06	$ 2.21	$ 2.36
Westar Energy, Inc.	WR	31.77	1.36	4.74%	9.12%	-33.57%	($31.77)	$ 1.39	$ 1.46	$ 1.53	$ 1.60	$ 1.68
Wisconsin Energy Corporation	WEC	41.21	1.36	6.91%	10.32%	-36.74%	($41.21)	$ 1.41	$ 1.50	$ 1.61	$ 1.72	$ 1.84
					Mean:	-34.46%						
					Median:	-34.66%						

Notes:

Source: Exhibit RAB-8 and Exhibit RAB-9

Mean projected growth rate excludes Mr. Baudino's Sustainable Growth rate since that rate was not used in his DCF calculations

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R-Squared of Beta Coefficient Regressions for Mr. Baudino's Proxy Group:
Value Line Methodology

Company	Ticker	R-Squared of Beta Coefficient
American Electric Power Company	AEP	0.4390
Black Hills Corporation	BKH	0.4460
Cleco Corporation	CNL	0.4010
CMS Energy Corporation	CMS	0.3970
Consolidated Edison, Inc.	ED	0.3150
Dominion Resources, Inc.	D	0.3990
Great Plains Energy Inc.	GXP	0.4870
Hawaiian Electric Industries, Inc.	HE	0.3150
Otter Tail Corporation	OTTR	0.4760
Pepco Holdings, Inc.	POM	0.4460
Pinnacle West Capital Corporation	PNW	0.5140
SCANA Corporation	SCG	0.4070
UIL Holdings Corporation	UIL	0.4240
UNS Energy Corporation	UNS	0.3860
Westar Energy, Inc.	WR	0.4900
Wisconsin Energy Corporation	WEC	0.3940
Mean		0.4210

Notes:

Source: Bloomberg Professional; Beta coefficients were calculated using Value Line's methodology which derives the Beta coefficient from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years.

Bond Yield Plus Risk Premium Analysis Applying 95.00% Confidence Interval

	[1]	[2]	[3]	[4]	[5]	95% Confidence Interval [6]	[7]
	Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity	Lower Bound Return on Equity	Upper Bound Return on Equity
Current	-3.08%	-2.94%	3.46%	6.81%	10.27%	9.67%	10.87%
Near Term Projected	-3.08%	-2.94%	3.73%	6.58%	10.32%	9.72%	10.91%
Long Term Projected	-3.08%	-2.94%	5.40%	5.50%	10.90%	10.34%	11.45%

SUMMARY OUTPUT

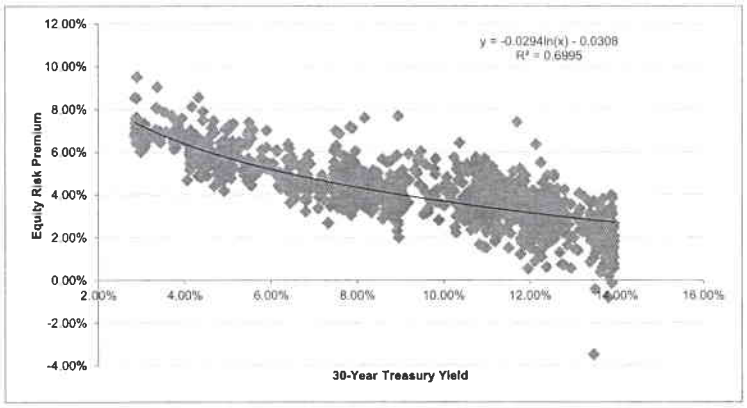
Regression Statistics	
Multiple R	0.836373
R Square	0.699520
Adjusted R Square	0.699306
Standard Error	0.008781
Observations	1410

ANOVA

	df	*SS*	*MS*	*F*	*Signif. F*
Regression	1	0.252753	0.252753	3277.831140	0.000000
Residual	1408	0.108571	0.000077		
Total	1409	0.361323			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-0.030846	0.001333	-23.136283	0.000000	-0.033461	-0.028230
X Variable 1	-0.029407	0.000514	-57.252346	0.000000	-0.030415	-0.028400

Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 32, No. 7, July 1, 2013, at 2,
Long-Term Projected = Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, 2013, at 14
[4] Equals [1] + [2] x ln([3])
[5] Equals [3] + [4]
[6] Using 95% confidence interval data reported in regression output: (lower bound constant + LN([3]) x upper bound slope) + [3]
[7] Using 95% confidence interval data reported in regression output: (upper bound constant + LN([3]) x lower bound slope) + [3]



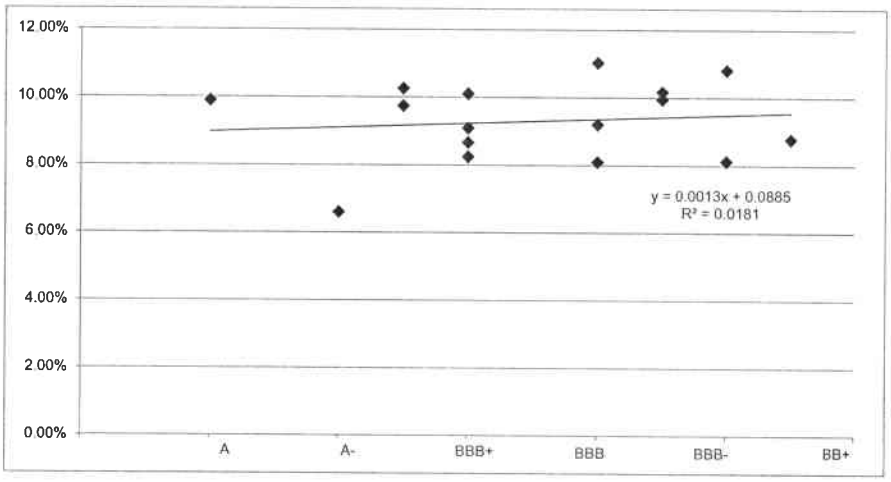
Source: Document No. 6

S&P Bond Credit Rating vs. DCF ROE Results - Mr. Baudino's Proxy Group

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	S&P Bond Rating	Moody's Bond Rating	Annual Dividend Yield	Mean Projected Growth	Constant Growth DCF
American Electric Power Co.	AEP	BBB	Baa2	4.09%	3.93%	8.10%
Black Hills Corporation	BKH	BBB+	A3	3.49%	6.50%	10.10%
Cleco Corporation	CNL	BBB	Baa2	3.04%	7.88%	11.03%
CMS Energy Corporation	CMS	BBB/BBB-	Baa2	3.74%	6.31%	10.17%
Consolidated Edison, Inc.	ED	A-	A3/Baa1	4.17%	2.39%	6.60%
Dominion Resources, Inc.	D	A	Baa1	3.93%	5.85%	9.89%
Great Plains Energy Inc.	GXP	BBB/BBB-	Baa1/Baa	3.88%	5.96%	9.95%
Hawaiian Electric Industries, Inc.	HE	BBB-	Baa2	4.65%	3.40%	8.13%
Otter Tail Corporation	OTTR	BBB-/BB+	Baa2	4.18%	4.50%	8.77%
Pepco Holdings, Inc.	POM	A-/BBB+	Baa1/Baa	5.23%	4.40%	9.75%
Pinnacle West Capital Corp.	PNW	BBB+	Baa1	3.89%	4.69%	8.67%
SCANA Corporation	SCG	BBB+	Baa1/Baa	4.05%	4.11%	8.25%
UIL Holdings Corporation	UIL	BBB	Baa2	4.46%	4.64%	9.20%
UNS Energy Corporation	UNS	BBB-	Baa2	3.70%	6.99%	10.82%
Westar Energy, Inc.	WR	BBB+	A3	4.25%	4.74%	9.09%
Wisconsin Energy Corporation	WEC	A-/BBB+	A2/A3	3.24%	6.91%	10.26%

Regression Results:

	Coefficients	Standard Error	T-Statistic
Intercept	0.088481938	0.009378771	9.434278625
Slope Coefficient	0.001278525	0.002516431	0.508070877



Notes:
[1] Source: Direct Testimony of Richard A. Baudino, at 20
[2] Source: Direct Testimony of Richard A. Baudino, at 20
[3] Source: Exhibit RAB-8
[4] Source: Exhibit RAB-9. Average of Value Line EPS & DPS, Zacks and Thomson Financial growth rates.
[5] Equals ([3] x (1 + 0.5 x [4])) + [4]

S&P Credit Rankings

U.S. Regulated Electric Utilities Company	Corp. Credit Rating	Business Profile	Financial Profile	Liquidity
San Diego Gas & Electric Co.	A/Stable/A-1	Excellent	Significant	Adequate
Wisconsin Public Service Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Southern Indiana Gas & Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
MidAmerican Energy Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Montana-Dakota Utilities Co.	BBB+/Stable/--	Excellent	Intermediate	Adequate
South Carolina Electric & Gas Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Kansas Gas & Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
LG&E and KU Energy LLC	BBB/Stable/--	Excellent	Aggressive	Adequate
Louisville Gas & Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Central Hudson Gas & Electric Corp.	A/Watch Neg/--	Excellent	Significant	Strong
Connecticut Light & Power Co.	A-/Stable/--	Excellent	Significant	Adequate
Consolidated Edison Co. of New York Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Massachusetts Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Narragansett Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Niagara Mohawk Power Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
NSTAR Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Orange and Rockland Utilities Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Western Massachusetts Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Atlantic City Electric Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
CenterPoint Energy Houston Electric LLC	BBB+/Watch Pos/--	Excellent	Aggressive	Strong
Central Maine Power Co.	BBB+/Negative/A-2	Excellent	Aggressive	Adequate
Delmarva Power & Light Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
New York State Electric & Gas Corp.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Oncor Electric Delivery Co. LLC	BBB+/Stable/--	Excellent	Aggressive	Strong
Potomac Electric Power Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Rochester Gas & Electric Corp.	BBB+/Negative/--	Excellent	Aggressive	Adequate
AEP Texas Central Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
AEP Texas North Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Commonwealth Edison Co.	BBB/Stable/A-2	Excellent	Significant	Strong
Green Mountain Power Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
PECO Energy Co.	BBB/Stable/A-2	Excellent	Significant	Strong
PPL Electric Utilities Corp.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Public Service Electric & Gas Co.	BBB/Positive/A-2	Excellent	Significant	Strong
UIL Holdings Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
United Illuminating Co. (The)	BBB/Stable/--	Excellent	Aggressive	Adequate
Ameren Illinois Co.	BBB/Watch Pos/A-2	Excellent	Significant	Adequate
Cleveland Electric Illuminating Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Duquesne Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Jersey Central Power & Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Metropolitan Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Electric Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Texas-New Mexico Power Co.	BBB/Stable/--	Excellent	Aggressive	Strong
West Penn Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Madison Gas & Electric Co.	AA-/Stable/A-1+	Excellent	Intermediate	Adequate
Alabama Power Co.	A/Stable/A-1	Excellent	Significant	Adequate
Georgia Power Co.	A/Stable/A-1	Excellent	Significant	Adequate
Gulf Power Co.	A/Stable/A-1	Excellent	Significant	Adequate
Mississippi Power Co.	A/Stable/A-1	Strong	Significant	Adequate
Florida Power & Light Co.	A-/Stable/A-2	Excellent	Intermediate	Adequate
Northern States Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Wisconsin	A-/Stable/A-2	Excellent	Significant	Adequate
PacifiCorp	A-/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of Colorado	A-/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of New Hampshire	A-/Stable/--	Excellent	Significant	Adequate
Southwestern Public Service Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Virginia Electric & Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Electric Power Co.	A-/Positive/A-2	Excellent	Significant	Adequate
Wisconsin Power & Light Co.	A/Stable/A-1	Excellent	Significant	Adequate
Carolina Power & Light Co. d/b/a Progess Energy Car	BBB+/Negative/A-2	Excellent	Significant	Adequate
DTE Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Duke Energy Carolinas LLC	BBB+/Negative/A-2	Excellent	Significant	Adequate
Duke Energy Indiana Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Duke Energy Kentucky Inc.	BBB+/Negative/--	Excellent	Significant	Adequate
Duke Energy Ohio Inc.	BBB+/Negative/A-2	Strong	Significant	Adequate
Florida Power Corp. d/b/a Progress Energy Florida Inc	BBB+/Negative/A-2	Excellent	Significant	Adequate
Interstate Power & Light Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Oklahoma Gas & Electric Co.	BBB+/Watch Pos/A-2	Excellent	Significant	Adequate

Business Profile

# Excellent	153
Total	173
% Excellent	88.44%

Financial Profile

# Significant or Intermediate	88
Total	173
% Significant	50.87%

S&P Credit Rankings

U.S. Regulated Electric Utilities Company	Corp. Credit Rating	Business Profile	Financial Profile	Liquidity
Southern California Edison Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Tampa Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Appalachian Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Arizona Public Service Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Cleco Power LLC	BBB/Positive/--	Excellent	Aggressive	Strong
El Paso Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Entergy Arkansas Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Gulf States Louisiana LLC	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Louisiana LLC	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Mississippi Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy New Orleans Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Texas Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Idaho Power Co.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Indiana Michigan Power Co.	BBB/Stable/--	Strong	Aggressive	Adequate
Kansas City Power & Light Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
KCP&L Greater Missouri Operations Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Utilities Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Ohio Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Pacific Gas & Electric Co.	BBB/Stable/A-2	Strong	Significant	Adequate
Portland General Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Public Service Co. of Oklahoma	BBB/Stable/--	Excellent	Aggressive	Adequate
Puget Sound Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Southwestern Electric Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Ameren Missouri	BBB/Watch Pos/A-2	Excellent	Significant	Adequate
Black Hills Power Inc.	BBB-/Positive/--	Excellent	Aggressive	Adequate
Consumers Energy Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Dayton Power & Light Co.	BB/Stable/--	Strong	Aggressive	Adequate
Empire District Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Hawaiian Electric Co. Inc.	BBB-/Stable/A-3	Strong	Aggressive	Adequate
Indianapolis Power & Light Co.	BBB-/Stable/--	Excellent	Highly leverage	Adequate
Monongahela Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Northern Indiana Public Service Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ohio Edison Co.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Otter Tail Power Co.	BBB-/Stable/--	Excellent	Significant	Adequate
Potomac Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Public Service Co. of New Mexico	BBB/Stable/--	Excellent	Aggressive	Strong
Toledo Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Nevada Power Co.	BBB-/Stable/--	Excellent	Aggressive	Strong
Sierra Pacific Power Co.	BBB-/Stable/--	Excellent	Aggressive	Strong
Tucson Electric Power Co.	BB+/Positive/--	Strong	Aggressive	Adequate
American Transmission Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
Midwest Independent Transmission System Operator	A+/Stable/--	Excellent	Intermediate	Exceptional
California Independent System Operator Corp.	A/Stable/--	Excellent	Intermediate	Strong
Southern Co.	A/Stable/A-1	Excellent	Significant	Adequate
Consolidated Edison Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Dominion Resources Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Integrys Energy Group Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid North America Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid USA	A-/Stable/A-2	Excellent	Significant	Adequate
New England Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
NextEra Energy Inc.	A-/Stable/--	Strong	Intermediate	Adequate
Northeast Utilities	A-/Stable/--	Excellent	Significant	Adequate
NSTAR LLC	A-/Stable/A-2	Excellent	Significant	Adequate
Vectren Corp.	A-/Stable/--	Excellent	Significant	Adequate
Vectren Utility Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Energy Corp.	A-/Positive/A-2	Excellent	Significant	Adequate
Xcel Energy Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
ALLETE Inc.	BBB+/Stable/A-2	Strong	Significant	Adequate
Alliant Energy Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
CenterPoint Energy Inc.	BBB+/Watch Pos/A-2	Excellent	Aggressive	Strong
DTE Energy Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Duke Energy Corp.	BBB+/Negative/A-2	Excellent	Significant	Adequate
International Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Great Plains LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Holdings Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Midwest LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Michigan Electric Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
MidAmerican Energy Holdings Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate

S&P Credit Rankings

U.S. Regulated Electric Utilities Company	Corp. Credit Rating	Business Profile	Financial Profile	Liquidity
OGE Energy Corp.	BBB+/Watch Pos/A-2	Strong	Significant	Adequate
PEPCO Holdings Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Progress Energy Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
SCANA Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Sempra Energy	BBB+/Stable/A-2	Strong	Significant	Adequate
TECO Energy Inc.	BBB+/Stable/--	Excellent	Significant	Adequate
American Electric Power Co. Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Avista Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Cleco Corp.	BBB/Positive/--	Excellent	Aggressive	Strong
Entergy Corp.	BBB/Stable/A-2	Strong	Significant	Adequate
Great Plains Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
IDACORP Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
NorthWestern Corp.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
PG&E Corp.	BBB/Stable/--	Strong	Significant	Adequate
Pinnacle West Capital Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
PPL Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
System Energy Resources Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Westar Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Ameren Corp.	BBB/Watch Pos/A-2	Excellent	Significant	Adequate
Black Hills Corp.	BBB-/Positive/--	Excellent	Aggressive	Adequate
CMS Energy Corp.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
DPL Inc.	BB/Stable/--	Strong	Aggressive	Adequate
Duquesne Light Holdings Inc.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Edison International	BBB-/Stable/--	Strong	Aggressive	Adequate
FirstEnergy Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Hawaiian Electric Industries Inc.	BBB-/Stable/A-3	Strong	Aggressive	Adequate
IPALCO Enterprises Inc.	BBB-/Stable/--	Excellent	Highly leverage	Adequate
Liberty Utilities Co.	BBB-/Positive/--	Excellent	Significant	Adequate
NiSource Inc.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Ohio Valley Electric Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Otter Tail Corp.	BBB-/Stable/--	Strong	Significant	Adequate
PNM Resources Inc.	BBB/Stable/--	Excellent	Aggressive	Strong
Trans-Allegheny Interstate Line Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
NV Energy Inc.	BBB-/Stable/--	Excellent	Aggressive	Strong
Puget Energy Inc.	BB+/Stable/--	Excellent	Aggressive	Strong

Source: Standard & Poors, U.S. Regulated Electric, Gas and Water Utilities; Strongest to Weakest, April 22, 2013.

Capital Expenditures Relative to Net Plant

Company	Ticker	5-Year CAPEX / 2014 Net Plant [1]
American Electric Power Company, Inc.	AEP	44.76%
Black Hills Corporation	BKH	60.48%
Cleco Corporation	CNL	21.03%
CMS Energy Corporation	CMS	51.77%
Consolidated Edison, Inc.	ED	40.12%
Dominion Resources, Inc.	D	50.50%
Great Plains Energy Inc.	GXP	42.09%
Hawaiian Electric Industries, Inc.	HE	68.50%
Otter Tail Corporation	OTTR	83.45%
Pepco Holdings, Inc.	POM	55.83%
Pinnacle West Capital Corporation	PNW	46.99%
SCANA Corporation	SCG	58.80%
UIL Holdings Corporation	UIL	43.51%
UniSource Energy Corporation	UNS	44.25%
Westar Energy, Inc.	WR	65.62%
Wisconsin Energy Corporation	WEC	32.11%
Average		50.61%
Median		48.74%
Tampa Electric Company [2]		54.38%

Notes:
[1] Source: Value Line; Value Line estimates 2014 and 2016 - 2018 CAPEX
[2] Source: Company Data

Annual Earnings Surprise

Company	Ticker	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Average
ALLETE, Inc.	ALE	2.84%	-13.25%	-10.41%	0.67%	58.74%	3.18%	0.97%	1.75%	-5.60%	3.96%	0.27%	**3.92%**
Alliant Energy Corporation	LNT	0.00%	-0.32%	-0.16%	22.37%	-10.22%	4.14%	-2.31%	5.43%	-0.04%	-1.99%	2.21%	**1.74%**
Ameren Corporation	AEE	-1.80%	-0.14%	3.16%	-0.45%	-3.03%	3.47%	2.82%	3.91%	-0.04%	1.31%	-0.66%	**0.78%**
American Electric Power Company, Inc.	AEP	-0.10%	12.90%	-11.71%	1.94%	1.65%	1.28%	2.18%	0.78%	-0.20%	-0.16%	1.54%	**0.92%**
Avista Corporation	AVA	5.02%	10.87%	-29.67%	10.13%	-0.20%	-10.98%	-4.76%	-3.80%	-0.18%	-1.60%	-8.79%	**-3.09%**
Black Hills Corporation	BKH	4.02%	-8.09%	5.90%	-23.72%	4.49%	4.16%	-6.00%	-15.70%	-5.24%	4.18%	2.35%	**-3.06%**
Cleco Corporation	CNL	10.15%	5.38%	-5.71%	129.22%	-2.65%	0.38%	2.22%	1.27%	1.12%	3.56%	1.23%	**13.29%**
CMS Energy Corporation	CMS	NA	NA	NA	-7.69%	5.57%	3.32%	5.31%	-36.50%	0.15%	4.47%	0.39%	**-3.12%**
Consolidated Edison, Inc.	ED	-0.03%	0.60%	0.26%	2.36%	2.97%	5.37%	0.03%	-2.76%	0.35%	1.53%	-0.69%	**0.91%**
Dominion Resources, Inc.	D	-0.29%	-3.43%	-1.66%	6.69%	0.55%	-3.10%	1.18%	0.99%	-0.45%	-2.12%	-0.20%	**-0.17%**
DTE Energy Company	DTE	-7.74%	-4.62%	0.61%	2.32%	29.93%	76.34%	-2.78%	0.61%	0.19%	2.70%	0.69%	**8.93%**
Duke Energy Corporation	DUK	4.10%	6.11%	-0.07%	4.32%	1.06%	1.52%	0.67%	1.84%	0.05%	3.35%	NA	**2.30%**
Edison International	EIX	7.05%	43.77%	7.34%	10.52%	5.26%	3.59%	0.92%	7.94%	0.09%	10.12%	22.58%	**10.83%**
Empire District Electric Company	EDE	0.00%	1.28%	-9.47%	-19.14%	20.00%	-7.23%	-1.10%	-3.52%	-6.02%	0.38%	6.88%	**-1.63%**
FirstEnergy Corp.	FE	16.76%	12.99%	9.14%	0.98%	0.81%	-0.55%	5.71%	1.35%	-0.96%	4.48%	-0.21%	**4.59%**
Great Plains Energy Inc.	GXP	15.90%	4.37%	10.86%	-0.37%	-4.93%	-4.96%	-12.46%	-9.48%	5.40%	-2.34%	3.05%	**0.46%**
Hawaiian Electric Industries, Inc.	HE	-1.10%	8.10%	-18.85%	0.51%	-12.79%	25.77%	-11.83%	16.74%	-8.19%	-0.35%	4.22%	**0.20%**
IDACORP, Inc.	IDA	114.47%	10.41%	-2.97%	6.92%	3.82%	-0.28%	-2.44%	5.90%	5.51%	-0.44%	0.72%	**12.87%**
MGE Energy, Inc.	MGEE	NA	NA	NA	NA	NA	NA	NA	2.79%	-4.94%	-4.35%	-0.89%	**-1.85%**
NextEra Energy, Inc.	NEE	3.31%	0.70%	6.25%	2.34%	4.47%	0.69%	0.00%	1.02%	-1.19%	0.39%	1.29%	**1.75%**
Northeast Utilities	NU	NA	NA	NA	-25.43%	-25.48%	3.65%	0.76%	3.92%	4.09%	2.10%	-0.18%	**-4.57%**
NorthWestern Corporation	NWE	NA	NA	NA	NA	NA	-5.08%	-0.84%	10.87%	5.42%	9.05%	0.59%	**3.34%**
Otter Tail Corporation	OTTR	1.13%	0.67%	0.33%	5.08%	0.18%	2.30%	-5.22%	-13.73%	-8.15%	-23.19%	11.21%	**-2.67%**
Pepco Holdings, Inc.	POM	NA	NA	NA	0.80%	-3.97%	-4.37%	2.17%	0.44%	12.93%	-3.54%	0.67%	**0.64%**
PG&E Corporation	PCG	5.38%	-19.57%	0.90%	2.01%	1.26%	0.54%	0.96%	0.63%	-0.35%	1.27%	0.47%	**-0.59%**
Pinnacle West Capital Corporation	PNW	4.18%	-5.24%	-4.05%	0.97%	-5.87%	3.71%	0.83%	-0.21%	2.02%	2.78%	1.86%	**0.09%**
PNM Resources, Inc.	PNM	-12.11%	-0.84%	-0.35%	1.16%	0.95%	-30.98%	-16.67%	10.82%	-0.80%	5.99%	1.31%	**-3.77%**
Portland General Electric Company	POR	NA	NA	NA	NA	-6.24%	8.57%	0.93%	-5.26%	-3.26%	-2.30%	-2.04%	**-1.37%**
PPL Corporation	PPL	3.51%	2.71%	0.92%	1.65%	1.02%	5.26%	-0.99%	8.88%	10.29%	3.15%	2.54%	**3.54%**
SCANA Corporation	SCG	-2.06%	-0.16%	-1.29%	1.53%	-4.36%	1.18%	1.62%	1.35%	-0.50%	-1.92%	-0.25%	**-0.44%**
Southern Company	SO	4.34%	2.87%	2.54%	0.24%	1.15%	0.78%	0.89%	0.39%	-0.08%	0.43%	2.25%	**1.44%**
UIL Holdings Corporation	UIL	-2.22%	6.15%	6.67%	8.35%	NA	-0.54%	0.90%	-0.36%	9.50%	14.99%	-2.79%	**4.07%**
UniSource Energy Corporation	UNS	NA	NA	NA	-3.35%	-4.44%	-1.57%	13.04%	-2.15%	3.74%	-3.53%	5.79%	**0.94%**
Westar Energy, Inc.	WR	NA	NA	2.04%	5.33%	5.32%	0.99%	-1.93%	-29.91%	-3.10%	0.95%	8.31%	**-1.33%**
Wisconsin Energy Corporation	WEC	3.76%	1.94%	-7.15%	1.09%	2.40%	4.48%	4.41%	2.30%	1.11%	1.58%	1.08%	**1.55%**
Xcel Energy Inc.	XEL	-1.81%	8.66%	3.45%	-1.23%	1.43%	1.71%	-0.96%	0.54%	-1.34%	-1.04%	0.94%	**0.94%**
Average		6.31%	3.03%	-1.49%	**4.49%**	2.09%	2.76%	**-0.62%**	-0.86%	0.31%	0.94%	**1.94%**	**1.45%**

Number of Over-Estimates	135
Number of Under-Estimates	226
Number of Exact Estimates	3

Notes:

Source: Bloomberg Professional

The year represents the fiscal year.

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Dr. Woolridge's Growth Rate Specific DCF Analysis

		Value Line			Yahoo	Zacks	Reuters
		Projected			Projected		
Company	Ticker	EPS	DPS	BVPS	EPS	EPS	EPS
ALLETE, Inc.	ALE	7.00%	3.50%	4.00%	6.00%	6.50%	6.00%
Alliant Energy Corporation	LNT	5.00%	4.50%	4.00%	5.90%	5.70%	5.90%
Ameren Corporation	AEE	-0.50%	1.50%	-0.05%	-1.20%	2.50%	-1.20%
American Electric Power Co.	AEP	4.50%	4.00%	4.00%	3.80%	3.40%	3.80%
Avista Corporation	AVA	4.00%	4.50%	3.00%	4.50%	4.30%	4.50%
Black Hills Corporation	BKH	11.50%	2.50%	3.00%	6.00%	6.00%	6.00%
Cleco Corp.	CNL	5.50%	10.00%	5.00%	8.00%	8.00%	8.00%
CMS Energy Corporation	CMS	5.50%	8.00%	5.50%	5.90%	5.80%	5.90%
Consolidated Edison, Inc.	ED	2.50%	1.50%	3.50%	3.20%	3.30%	3.20%
Dominion Resources, Inc.	D	6.00%	5.50%	4.50%	7.30%	4.60%	6.80%
DTE Energy Company	DTE	4.00%	5.50%	4.00%	4.60%	4.70%	4.60%
Duke Energy Corporation	DUK	4.00%	2.00%	3.00%	4.20%	3.90%	4.20%
Edison International	EIX	2.50%	5.50%	4.50%	-0.20%	4.60%	0.80%
FirstEnergy Corporation	FE	3.50%	0.00%	2.50%	3.60%	0.60%	3.50%
Great Plains Energy Incorporated	GXP	6.50%	6.00%	2.50%	6.30%	5.10%	6.30%
Hawaiian Electric Industries, Inc.	HE	5.50%	2.00%	4.50%	2.40%	3.70%	3.70%
IDACORP, Inc.	IDA	2.00%	7.00%	4.50%	4.00%	4.00%	NA
MGE Energy, Inc.	MGEE	4.50%	3.50%	5.00%	4.00%	4.00%	NA
Nextera Energy	NEE	5.00%	8.50%	6.00%	6.40%	6.10%	6.10%
Northeast Utilities	NU	8.00%	8.00%	6.00%	7.70%	7.10%	7.10%
NorthWestern Corporation	NWE	3.00%	4.00%	4.50%	5.00%	5.00%	NA
Pepco Holdings, Inc.	POM	6.00%	1.00%	2.00%	4.60%	6.00%	4.60%
PG&E Corporation	PCG	4.00%	2.50%	3.00%	3.10%	1.40%	3.70%
Pinnacle West Capital Gorp.	PNW	5.00%	2.00%	3.50%	6.00%	4.10%	6.00%
PNM Resources, Inc.	PNM	12.00%	12.50%	4.00%	6.40%	7.30%	6.40%
Portland General Electric Company	POR	3.50%	3.50%	3.50%	5.70%	6.50%	5.80%
PPL Corporation	PPL	0.00%	2.00%	5.00%	6.00%	-3.10%	6.00%
SCANA Corporation	SCG	4.50%	2.50%	5.50%	4.80%	4.70%	4.90%
Southern Company	SO	4.50%	3.50%	4.00%	4.80%	4.80%	5.00%
UIL Holdings Corporation	UIL	4.00%	0.00%	4.50%	8.10%	6.50%	7.00%
UNS Energy Corp.	UNS	6.50%	5.50%	5.50%	8.00%	8.00%	NA
Westar Energy, Inc.	WR	6.00%	3.00%	5.00%	4.80%	5.10%	4.80%
Wisconsin Energy Corporation	WEC	5.50%	12.00%	3.50%	4.90%	5.20%	4.90%
Xcel Energy Inc.	XEL	4.50%	4.50%	4.50%	5.10%	4.90%	5.40%
Average		4.87%	4.47%	4.03%	4.99%	4.71%	4.99%
Dividend Yield		4.10%	4.10%	4.10%	4.10%	4.10%	4.10%
Adjusted Dividend Yield		4.20%	4.19%	4.18%	4.20%	4.20%	4.20%
Equity Cost Rate		**9.07%**	**8.66%**	**8.21%**	**9.19%**	**8.91%**	**9.19%**

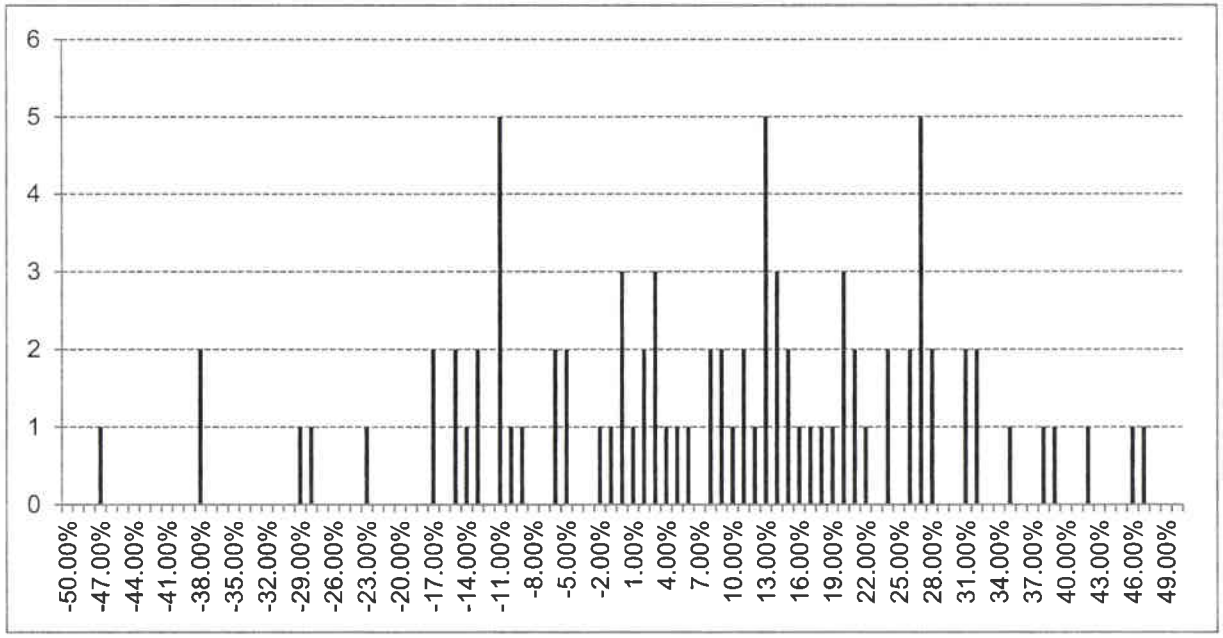
Source: Exhibit JRW-10

Woolridge Growth Rate Specific DCF Analysis
Removing Growth Rates Less than or Equal to 0.00

		Value Line Projected			Yahoo	Zacks Projected	Reuters
Company	Ticker	EPS	DPS	BVPS	EPS	EPS	EPS
ALLETE, Inc.	ALE	7.00%	3.50%	4.00%	6.00%	6.50%	6.00%
Alliant Energy Corporation	LNT	5.00%	4.50%	4.00%	5.90%	5.70%	5.90%
Ameren Corporation	AEE		1.50%			2.50%	
American Electric Power Co.	AEP	4.50%	4.00%	4.00%	3.80%	3.40%	3.80%
Avista Corporation	AVA	4.00%	4.50%	3.00%	4.50%	4.30%	4.50%
Black Hills Corporation	BKH	11.50%	2.50%	3.00%	6.00%	6.00%	6.00%
Cleco Corp.	CNL	5.50%	10.00%	5.00%	8.00%	8.00%	8.00%
CMS Energy Corporation	CMS	5.50%	8.00%	5.50%	5.90%	5.80%	5.90%
Consolidated Edison, Inc.	ED	2.50%	1.50%	3.50%	3.20%	3.30%	3.20%
Dominion Resources, Inc.	D	6.00%	5.50%	4.50%	7.30%	4.60%	6.80%
DTE Energy Company	DTE	4.00%	5.50%	4.00%	4.60%	4.70%	4.60%
Duke Energy Corporation	DUK	4.00%	2.00%	3.00%	4.20%	3.90%	4.20%
Edison International	EIX	2.50%	5.50%	4.50%		4.60%	0.80%
FirstEnergy Corporation	FE	3.50%		2.50%	3.60%	0.60%	3.50%
Great Plains Energy Incorporated	GXP	6.50%	6.00%	2.50%	6.30%	5.10%	6.30%
Hawaiian Electric Industries, Inc.	HE	5.50%	2.00%	4.50%	2.40%	3.70%	3.70%
IDACORP, Inc.	IDA	2.00%	7.00%	4.50%	4.00%	4.00%	NA
MGE Energy, Inc.	MGEE	4.50%	3.50%	5.00%	4.00%	4.00%	NA
Nextera Energy	NEE	5.00%	8.50%	6.00%	6.40%	6.10%	6.10%
Northeast Utilities	NU	8.00%	8.00%	6.00%	7.70%	7.10%	7.10%
NorthWestern Corporation	NWE	3.00%	4.00%	4.50%	5.00%	5.00%	NA
Pepco Holdings, Inc.	POM	6.00%	1.00%	2.00%	4.60%	6.00%	4.60%
PG&E Corporation	PCG	4.00%	2.50%	3.00%	3.10%	1.40%	3.70%
Pinnacle West Capital Gorp.	PNW	5.00%	2.00%	3.50%	6.00%	4.10%	6.00%
PNM Resources, Inc.	PNM	12.00%	12.50%	4.00%	6.40%	7.30%	6.40%
Portland General Electric Company	POR	3.50%	3.50%	3.50%	5.70%	6.50%	5.80%
PPL Corporation	PPL		2.00%	5.00%	6.00%		6.00%
SCANA Corporation	SCG	4.50%	2.50%	5.50%	4.80%	4.70%	4.90%
Southern Company	SO	4.50%	3.50%	4.00%	4.80%	4.80%	5.00%
UIL Holdings Corporation	UIL	4.00%		4.50%	8.10%	6.50%	7.00%
UNS Energy Corp.	UNS	6.50%	5.50%	5.50%	8.00%	8.00%	NA
Westar Energy, Inc.	WR	6.00%	3.00%	5.00%	4.80%	5.10%	4.80%
Wisconsin Energy Corporation	WEC	5.50%	12.00%	3.50%	4.90%	5.20%	4.90%
Xcel Energy Inc.	XEL	4.50%	4.50%	4.50%	5.10%	4.90%	5.40%
Average		5.19%	4.75%	4.15%	5.35%	4.95%	5.20%
Dividend Yield		4.10%	4.10%	4.10%	4.10%	4.10%	4.10%
Adjusted Dividend Yield		4.21%	4.20%	4.19%	4.21%	4.20%	4.21%
Equity Cost Rate		**9.39%**	**8.95%**	**8.34%**	**9.56%**	**9.15%**	**9.41%**
Average DPS and BVPS		**8.64%**					
Average EPS		**9.38%**					

Source: Exhibit JRW-10

Frequency Distribution of Capital Appreciation Returns, 1926 - 2012



Source: See Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, Table B-3, pg 186-187

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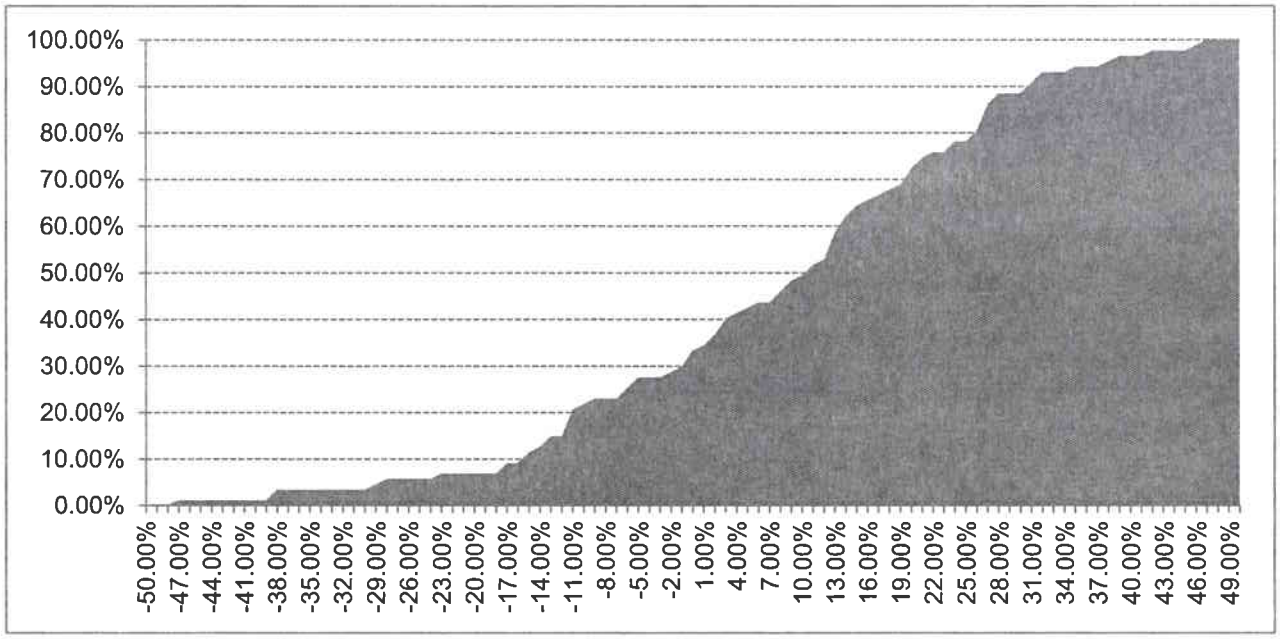
Cumulative Probability of Capital Appreciation Returns, 1926 - 2012



Source: See Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, Table B-3, pg 186-187

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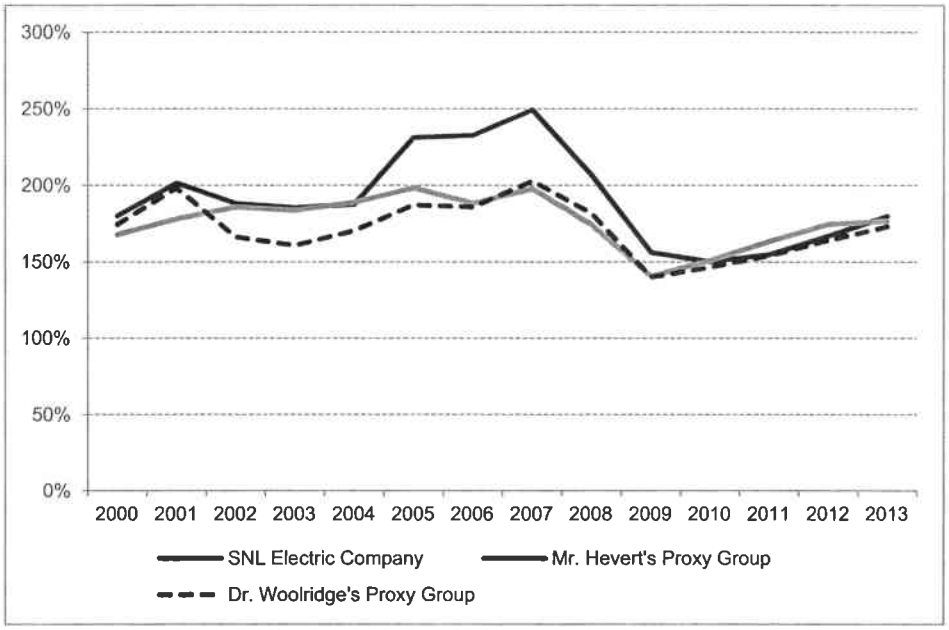
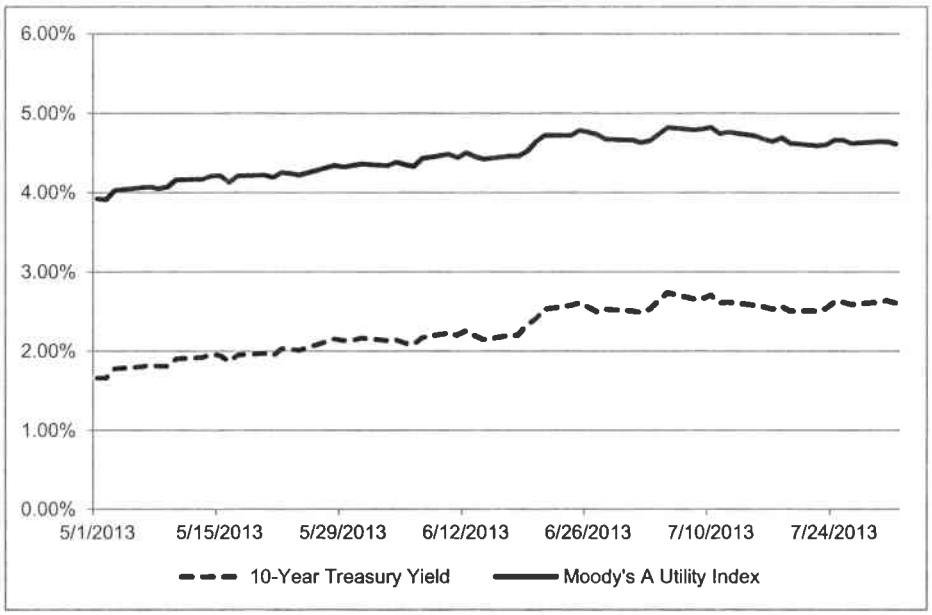
Market to Book Ratios



Year	SNL Electric	Mr.	Dr.
2000	180%	168%	174%
2001	201%	178%	198%
2002	188%	186%	166%
2003	185%	184%	161%
2004	187%	189%	170%
2005	231%	198%	187%
2006	233%	188%	186%
2007	249%	198%	203%
2008	207%	174%	182%
2009	156%	141%	140%
2010	150%	151%	146%
2011	155%	164%	154%
2012	167%	175%	164%
2013	180%	177%	173%

Source: SNL Financial

Review of Recent Interest Rates



Date	Yield	Index
5/1/2013	1.66%	3.92%
5/2/2013	1.66%	3.91%
5/3/2013	1.78%	4.03%
5/6/2013	1.80%	4.06%
5/7/2013	1.82%	4.07%
5/8/2013	1.81%	4.05%
5/9/2013	1.81%	4.07%
5/10/2013	1.90%	4.16%
5/13/2013	1.92%	4.17%
5/14/2013	1.96%	4.21%
5/15/2013	1.94%	4.21%
5/16/2013	1.87%	4.13%
5/17/2013	1.95%	4.21%
5/20/2013	1.97%	4.22%
5/21/2013	1.94%	4.19%
5/22/2013	2.03%	4.25%
5/23/2013	2.02%	4.24%
5/24/2013	2.01%	4.22%
5/28/2013	2.15%	4.34%
5/29/2013	2.13%	4.32%
5/30/2013	2.13%	4.34%
5/31/2013	2.16%	4.36%
6/3/2013	2.13%	4.34%

6/4/2013	2.14%	4.38%
6/5/2013	2.10%	4.35%
6/6/2013	2.08%	4.33%
6/7/2013	2.17%	4.43%
6/10/2013	2.22%	4.48%
6/11/2013	2.20%	4.44%
6/12/2013	2.25%	4.50%
6/13/2013	2.19%	4.45%
6/14/2013	2.14%	4.42%
6/17/2013	2.19%	4.46%
6/18/2013	2.20%	4.46%
6/19/2013	2.33%	4.52%
6/20/2013	2.41%	4.64%
6/21/2013	2.52%	4.72%
6/24/2013	2.57%	4.72%
6/25/2013	2.60%	4.78%
6/26/2013	2.55%	4.76%
6/27/2013	2.49%	4.73%
6/28/2013	2.52%	4.67%
7/1/2013	2.50%	4.66%
7/2/2013	2.48%	4.63%
7/3/2013	2.52%	4.65%
7/5/2013	2.73%	4.82%
7/8/2013	2.65%	4.79%
7/9/2013	2.65%	4.80%
7/10/2013	2.70%	4.82%
7/11/2013	2.60%	4.74%
7/12/2013	2.61%	4.76%
7/15/2013	2.57%	4.71%
7/16/2013	2.55%	4.67%
7/17/2013	2.52%	4.64%
7/18/2013	2.56%	4.69%
7/19/2013	2.50%	4.62%
7/22/2013	2.50%	4.59%
7/23/2013	2.53%	4.60%
7/24/2013	2.61%	4.66%
7/25/2013	2.61%	4.66%
7/26/2013	2.58%	4.62%
7/29/2013	2.61%	4.64%
7/30/2013	2.63%	4.64%
7/31/2013	2.60%	4.61%

Source: Bloomberg Professional

Mr. Hevert's Proxy Group Capital Structure

Average Operating Company Capital Structure

Company	Ticker	% Common Equity 2013Q1	2012Q4	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2	Average
American Electric Power Company, Inc.	AEP	48.42%	48.17%	48.05%	47.67%	47.22%	48.97%	49.44%	48.00%	48.24%
Cleco Corporation	CNL	50.90%	50.29%	49.77%	48.91%	48.38%	48.08%	47.52%	47.75%	48.95%
Empire District Electric Company	EDE	52.47%	52.23%	53.03%	51.81%	52.02%	51.82%	51.79%	50.24%	51.93%
Great Plains Energy Inc.	GXP	50.09%	50.99%	51.77%	47.37%	49.13%	50.07%	50.74%	49.18%	49.92%
IDACORP, Inc.	IDA	51.30%	51.39%	51.53%	50.21%	50.88%	50.59%	50.44%	48.95%	50.66%
Otter Tail Corporation	OTTR	52.60%	51.98%	49.45%	49.57%	50.31%	50.28%	51.81%	51.86%	50.98%
Pinnacle West Capital Corporation	PNW	55.84%	55.75%	56.30%	53.78%	52.76%	54.46%	52.06%	52.44%	54.17%
PNM Resources, Inc.	PNM	49.34%	50.35%	51.08%	48.68%	49.53%	48.61%	46.70%	45.64%	48.74%
Portland General Electric Company	POR	51.78%	51.11%	49.74%	49.47%	49.37%	48.51%	47.90%	47.78%	49.46%
Southern Company	SO	47.17%	47.64%	47.91%	46.66%	45.65%	46.50%	50.96%	49.54%	47.75%
Westar Energy, Inc.	WR	59.50%	59.65%	58.96%	57.26%	58.19%	59.31%	57.87%	56.29%	58.38%
									Minimum	47.75%
									Maximum	58.38%

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Operating Company Capital Structure

Operating Company	Parent	% Common Equity 2013Q1	2012Q4	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2
Appalachian Power Company	AEP	44.73%	44.06%	44.04%	43.63%	43.41%	42.80%	44.19%	43.14%
AEP Texas Central Company	AEP	45.98%	46.84%	47.67%	46.97%	45.78%	62.61%	60.84%	47.26%
Indiana Michigan Power Company	AEP	46.88%	49.59%	49.61%	49.42%	49.55%	49.13%	49.10%	48.64%
Kentucky Power Company	AEP	46.67%	46.02%	46.46%	46.12%	45.76%	45.61%	45.62%	45.42%
Ohio Power Company	AEP	54.92%	53.77%	54.38%	53.94%	53.49%	52.12%	53.92%	54.34%
Public Service Company of Oklahoma	AEP	48.47%	49.10%	49.69%	48.93%	48.40%	48.52%	48.56%	47.51%
Southwestern Electric Power Company	AEP	50.54%	50.80%	50.42%	49.27%	48.55%	49.96%	51.38%	50.32%
AEP Texas North Company	AEP	44.02%	44.42%	44.68%	44.43%	44.81%	45.25%	45.26%	43.74%
Kingsport Power Company	AEP	42.96%	44.51%	44.60%	47.42%	48.58%	48.27%	47.26%	50.87%
Wheeling Power Company	AEP	59.03%	52.59%	48.95%	46.54%	43.84%	45.44%	48.30%	48.72%
Cleco Power LLC	CNL	50.90%	50.29%	49.77%	48.91%	48.38%	48.08%	47.52%	47.75%
Empire District Electric Company	EDE	52.47%	52.23%	53.03%	51.81%	52.02%	51.82%	51.79%	50.24%
KCP&L Greater Missouri Operations Company	GXP	53.21%	54.00%	54.19%	47.22%	50.04%	51.45%	51.77%	50.29%
Kansas City Power & Light Company	GXP	46.97%	47.99%	49.36%	47.51%	48.21%	48.69%	49.71%	48.08%
Idaho Power Co.	IDA	51.30%	51.39%	51.53%	50.21%	50.88%	50.59%	50.44%	48.95%
Otter Tail Power Company	OTTR	52.60%	51.98%	49.45%	49.57%	50.31%	50.28%	51.81%	51.86%
Arizona Public Service Company	PNW	55.84%	55.75%	56.30%	53.78%	52.76%	54.46%	52.06%	52.44%
Public Service Company of New Mexico	PNM	49.34%	50.35%	51.08%	48.68%	49.53%	48.61%	46.70%	45.64%
Portland General Electric Company	POR	51.78%	51.11%	49.74%	49.47%	49.37%	48.51%	47.90%	47.78%
Georgia Power Company	SO	48.21%	49.05%	49.60%	47.90%	48.51%	50.24%	51.93%	49.83%
Alabama Power Company	SO	46.49%	46.59%	47.52%	46.81%	45.57%	46.53%	47.29%	46.71%
Gulf Power Company	SO	46.80%	46.20%	48.35%	46.07%	46.72%	45.41%	47.06%	45.62%
Mississippi Power Company	SO	NA	48.71%	46.17%	45.88%	41.82%	43.83%	57.54%	55.99%
Kansas Gas and Electric Company	WR	62.22%	62.02%	59.27%	58.30%	57.85%	57.55%	57.70%	56.77%
Westar Energy (KPL)	WR	56.78%	57.28%	58.65%	56.21%	58.54%	61.07%	58.04%	55.80%

Source: SNL Financial

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Mr. Hevert's Proxy Group Capital Structure

Average Operating Company Capital Structure

Company	Ticker	% Debt 2013Q1	2012Q4	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2	Average
American Electric Power Company, Inc.	AEP	51.58%	51.83%	51.95%	52.33%	52.78%	51.03%	50.56%	52.00%	51.76%
Cleco Corporation	CNL	49.10%	49.71%	50.23%	51.09%	51.62%	51.92%	52.48%	52.25%	51.05%
Empire District Electric Company	EDE	47.53%	47.77%	46.97%	48.19%	47.98%	48.18%	48.21%	49.76%	48.07%
Great Plains Energy Inc.	GXP	49.91%	49.01%	48.23%	52.63%	50.87%	49.93%	49.26%	50.82%	50.08%
IDACORP, Inc.	IDA	48.70%	48.61%	48.47%	49.79%	49.12%	49.41%	49.56%	51.05%	49.34%
Otter Tail Corporation	OTTR	47.40%	48.02%	50.55%	50.43%	49.69%	49.72%	48.19%	48.14%	49.02%
Pinnacle West Capital Corporation	PNW	44.16%	44.25%	43.70%	46.22%	47.24%	45.54%	47.94%	47.56%	45.83%
PNM Resources, Inc.	PNM	50.66%	49.65%	48.92%	51.32%	50.47%	51.39%	53.30%	54.36%	51.26%
Portland General Electric Company	POR	48.22%	48.89%	50.26%	50.53%	50.63%	51.49%	52.10%	52.22%	50.54%
Southern Company	SO	52.83%	52.36%	52.09%	53.34%	54.35%	53.50%	49.04%	50.46%	52.25%
Westar Energy, Inc.	WR	40.50%	40.35%	41.04%	42.74%	41.81%	40.69%	42.13%	43.71%	41.62%
									Minimum	41.62%
									Maximum	52.25%

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Operating Company Capital Structure

Operating Company	Parent	% Debt 2013Q1	2012Q4	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2
Appalachian Power Company	AEP	55.27%	55.94%	55.96%	56.37%	56.59%	57.20%	55.81%	56.86%
AEP Texas Central Company	AEP	54.02%	53.16%	52.33%	53.03%	54.22%	37.39%	39.16%	52.74%
Indiana Michigan Power Company	AEP	53.12%	50.41%	50.39%	50.58%	50.45%	50.87%	50.90%	51.36%
Kentucky Power Company	AEP	53.33%	53.98%	53.54%	53.88%	54.24%	54.39%	54.38%	54.58%
Ohio Power Company	AEP	45.08%	46.23%	45.62%	46.06%	46.51%	47.88%	46.08%	45.66%
Public Service Company of Oklahoma	AEP	51.53%	50.90%	50.31%	51.07%	51.60%	51.48%	51.44%	52.49%
Southwestern Electric Power Company	AEP	49.46%	49.20%	49.58%	50.73%	51.45%	50.04%	48.62%	49.68%
AEP Texas North Company	AEP	55.98%	55.58%	55.32%	55.57%	55.19%	54.75%	54.74%	56.26%
Kingsport Power Company	AEP	57.04%	55.49%	55.40%	52.58%	51.42%	51.73%	52.74%	49.13%
Wheeling Power Company	AEP	40.97%	47.41%	51.05%	53.46%	56.16%	54.56%	51.70%	51.28%
Cleco Power LLC	CNL	49.10%	49.71%	50.23%	51.09%	51.62%	51.92%	52.48%	52.25%
Empire District Electric Company	EDE	47.53%	47.77%	46.97%	48.19%	47.98%	48.18%	48.21%	49.76%
KCP&L Greater Missouri Operations Company	GXP	46.79%	46.00%	45.81%	52.78%	49.96%	48.55%	48.23%	49.71%
Kansas City Power & Light Company	GXP	53.03%	52.01%	50.64%	52.49%	51.79%	51.31%	50.29%	51.92%
Idaho Power Co.	IDA	48.70%	48.61%	48.47%	49.79%	49.12%	49.41%	49.56%	51.05%
Otter Tail Power Company	OTTR	47.40%	48.02%	50.55%	50.43%	49.69%	49.72%	48.19%	48.14%
Arizona Public Service Company	PNW	44.16%	44.25%	43.70%	46.22%	47.24%	45.54%	47.94%	47.56%
Public Service Company of New Mexico	PNM	50.66%	49.65%	48.92%	51.32%	50.47%	51.39%	53.30%	54.36%
Portland General Electric Company	POR	48.22%	48.89%	50.26%	50.53%	50.63%	51.49%	52.10%	52.22%
Georgia Power Company	SO	51.79%	50.95%	50.40%	52.10%	51.49%	49.76%	48.07%	50.17%
Alabama Power Company	SO	53.51%	53.41%	52.48%	53.19%	54.43%	53.47%	52.71%	53.29%
Gulf Power Company	SO	53.20%	53.80%	51.65%	53.93%	53.28%	54.59%	52.94%	54.38%
Mississippi Power Company	SO	NA	51.29%	53.83%	54.12%	58.18%	56.17%	42.46%	44.01%
Kansas Gas and Electric Company	WR	37.78%	37.98%	40.73%	41.70%	42.15%	42.45%	42.30%	43.23%
Westar Energy (KPL)	WR	43.22%	42.72%	41.35%	43.79%	41.46%	38.93%	41.96%	44.20%

Source: SNL Financial

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Dr. Woolridge's Proxy Group Capital Structure

Average Operating Company Capital Structure

		% Common Equity								
Company	Ticker	2013Q1	2012Q4	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2	Average
ALLETE, Inc.	ALE	57.17%	55.56%	55.45%	59.39%	59.36%	56.17%	57.75%	58.92%	57.47%
Alliant Energy Corporation	LNT	51.21%	51.11%	53.33%	51.71%	51.78%	52.18%	52.30%	51.41%	51.88%
Ameren Corporation	AEE	54.68%	54.61%	55.27%	55.26%	55.38%	55.69%	56.55%	56.19%	55.45%
American Electric Power Co.	AEP	48.42%	48.17%	48.05%	47.67%	47.22%	48.97%	49.44%	48.00%	48.24%
Avista Corporation	AVA	48.64%	48.17%	49.66%	48.61%	48.91%	47.97%	48.65%	48.82%	48.68%
Black Hills Corporation	BKH	55.25%	55.64%	55.52%	55.00%	57.35%	56.57%	55.97%	55.30%	55.83%
Cleco Corp.	CNL	50.90%	50.29%	49.77%	48.91%	48.38%	48.08%	47.52%	47.75%	48.95%
CMS Energy Corporation	CMS	52.45%	50.57%	51.26%	53.18%	52.69%	50.19%	50.24%	49.18%	51.22%
Consolidated Edison, Inc.	ED	54.22%	53.98%	54.19%	53.05%	53.37%	53.45%	53.66%	53.31%	53.65%
Dominion Resources, Inc.	D	53.40%	53.88%	55.40%	53.38%	53.92%	53.01%	54.25%	52.92%	53.77%
DTE Energy Company	DTE	47.61%	48.46%	48.31%	46.43%	48.47%	48.62%	48.21%	47.40%	47.94%
Duke Energy Corporation	DUK	55.25%	54.73%	55.19%	54.04%	54.20%	54.33%	55.71%	57.17%	55.08%
Edison International	EIX	51.06%	52.49%	50.17%	49.71%	49.48%	50.18%	50.59%	50.66%	50.54%
FirstEnergy Corporation	FE	46.06%	46.08%	47.25%	46.34%	45.88%	46.20%	46.52%	45.03%	46.17%
Great Plains Energy Incorporated	GXP	50.09%	50.99%	51.77%	47.37%	49.13%	50.07%	50.74%	49.18%	49.92%
Hawaiian Electric Industries, Inc.	HE	54.77%	55.61%	54.16%	53.82%	55.99%	57.77%	56.66%	56.59%	55.67%
IDACORP, Inc.	IDA	51.30%	51.39%	51.53%	50.21%	50.88%	50.59%	50.44%	48.95%	50.66%
MGE Energy, Inc.	MGEE	60.47%	60.38%	60.48%	59.67%	59.68%	59.19%	59.45%	59.02%	59.79%
Nextera Energy	NEE	58.66%	59.89%	58.69%	57.63%	57.32%	58.16%	59.12%	56.67%	58.27%
Northeast Utilities	NU	50.43%	50.31%	48.89%	48.61%	49.66%	51.46%	50.65%	50.41%	50.05%
NorthWestern Corporation	NWE	47.02%	44.22%	45.72%	46.54%	46.36%	44.49%	45.16%	45.75%	45.66%
Pepco Holdings, Inc.	POM	44.90%	44.43%	44.89%	43.95%	44.57%	45.54%	46.34%	45.45%	45.01%
PG&E Corporation	PCG	51.31%	50.50%	50.14%	49.41%	48.79%	47.24%	48.45%	47.95%	49.22%
Pinnacle West Capital Gorp.	PNW	55.84%	55.75%	56.30%	53.78%	52.76%	54.46%	52.06%	52.44%	54.17%
PNM Resources, Inc.	PNM	49.34%	50.35%	51.08%	48.68%	49.53%	48.61%	46.70%	45.64%	48.74%
Portland General Electric Company	POR	51.78%	51.11%	49.74%	49.47%	49.37%	48.51%	47.90%	47.78%	49.46%
PPL Corporation	PPL	57.17%	57.08%	57.71%	57.01%	57.84%	57.78%	57.42%	57.98%	57.50%
SCANACorporation	SCG	51.69%	50.51%	50.66%	50.03%	50.49%	51.64%	51.36%	50.86%	50.91%
Southern Company	SO	47.17%	47.64%	47.91%	46.66%	45.65%	46.50%	50.96%	49.54%	47.75%
UIL Holdings Corporation	UIL	49.30%	50.22%	49.61%	49.13%	43.07%	43.39%	45.88%	46.44%	47.13%
UNS Energy Corp.	UNS	46.38%	46.82%	46.54%	46.66%	46.40%	47.11%	47.27%	46.30%	46.69%
Westar Energy, Inc.	WR	59.50%	59.65%	58.96%	57.26%	58.19%	59.31%	57.87%	56.29%	58.38%
Wisconsin Energy Corporation	WEC	56.82%	56.22%	60.28%	58.92%	56.03%	54.82%	56.97%	58.82%	57.36%
Xcel Energy Inc.	XEL	53.42%	52.51%	51.97%	53.40%	53.77%	53.80%	54.51%	53.72%	53.39%
									Minimum	45.01%
									Maximum	59.79%

Dr. Woolridge's Proxy Group Capital Structure
Operating Company Capital Structure

Operating Company	Parent	% Common Equity 2013Q1	2012Q4	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2
ALLETE (Minnesota Power)	ALE	56.09%	55.30%	54.41%	57.43%	57.69%	56.92%	56.28%	58.10%
Superior Water, Light and Power Company	ALE	58.24%	55.83%	56.49%	61.35%	61.03%	55.42%	59.22%	59.74%
Interstate Power and Light Company	LNT	52.55%	51.45%	51.52%	49.48%	49.57%	50.51%	50.31%	48.97%
Wisconsin Power and Light Company	LNT	49.86%	50.77%	55.13%	53.93%	53.99%	53.85%	54.29%	53.84%
Ameren Illinois Company	AEE	57.93%	57.44%	58.25%	59.12%	59.19%	59.30%	59.81%	59.72%
Union Electric Company	AEE	51.42%	51.77%	52.29%	51.39%	51.58%	52.08%	53.30%	52.66%
AEP Texas Central Company	AEP	45.98%	46.84%	47.67%	46.97%	45.78%	62.61%	60.84%	47.26%
AEP Texas North Company	AEP	44.02%	44.42%	44.68%	44.43%	44.81%	45.25%	45.26%	43.74%
Appalachian Power Company	AEP	44.73%	44.06%	44.04%	43.63%	43.41%	42.80%	44.19%	43.14%
Indiana Michigan Power Company	AEP	46.88%	49.59%	49.61%	49.42%	49.55%	49.13%	49.10%	48.64%
Kentucky Power Company	AEP	46.67%	46.02%	46.46%	46.12%	45.76%	45.61%	45.62%	45.42%
Kingsport Power Company	AEP	42.96%	44.51%	44.60%	47.42%	48.58%	48.27%	47.26%	50.87%
Ohio Power Company	AEP	54.92%	53.77%	54.38%	53.94%	53.49%	52.12%	53.92%	54.34%
Public Service Company of Oklahoma	AEP	48.47%	49.10%	49.69%	48.93%	48.40%	48.52%	48.56%	47.51%
Southwestern Electric Power Company	AEP	50.54%	50.80%	50.42%	49.27%	48.55%	49.96%	51.38%	50.32%
Wheeling Power Company	AEP	59.03%	52.59%	48.95%	46.54%	43.84%	45.44%	48.30%	48.72%
Avista Corporation	AVA	48.64%	48.17%	49.66%	48.61%	48.91%	47.97%	48.65%	48.82%
Black Hills Power, Inc.	BKH	54.63%	54.20%	53.72%	53.07%	55.93%	54.90%	54.38%	53.58%
Cheyenne Light, Fuel and Power Company	BKH	55.86%	57.09%	57.33%	56.92%	58.77%	58.23%	57.56%	57.03%
Cleco Power LLC	CNL	50.90%	50.29%	49.77%	48.91%	48.38%	48.08%	47.52%	47.75%
Consumers Energy Company	CMS	52.45%	50.57%	51.26%	53.18%	52.69%	50.19%	50.24%	49.18%
Consolidated Edison Company of New York,	ED	50.70%	50.69%	50.86%	48.52%	50.44%	51.19%	51.12%	50.67%
Orange and Rockland Utilities, Inc.	ED	48.78%	48.69%	48.75%	48.01%	47.87%	47.03%	47.96%	47.34%
Pike County Light and Power Company	ED	63.18%	62.57%	62.95%	62.63%	61.80%	62.13%	61.89%	61.92%
Virginia Electric and Power Company	D	53.40%	53.88%	55.40%	53.38%	53.92%	53.01%	54.25%	52.92%
DTE Electric Company	DTE	47.61%	48.46%	48.31%	46.43%	48.47%	48.62%	48.21%	47.40%
Duke Energy Carolinas, LLC	DUK	53.74%	53.13%	52.12%	53.92%	53.38%	50.57%	53.87%	53.04%
Duke Energy Florida, Inc.	DUK	49.82%	48.33%	50.74%	49.22%	49.26%	49.75%	51.41%	50.80%
Duke Energy Indiana, Inc.	DUK	50.39%	49.42%	49.23%	48.97%	48.01%	50.06%	51.57%	51.88%
Duke Energy Kentucky, Inc.	DUK	54.13%	52.90%	52.66%	53.00%	52.46%	51.66%	52.12%	59.51%
Duke Energy Ohio, Inc.	DUK	73.37%	74.20%	75.86%	70.71%	70.52%	70.34%	70.20%	70.79%
Duke Energy Progress, Inc.	DUK	50.07%	50.38%	50.55%	48.42%	51.56%	53.59%	55.11%	56.97%
Southern California Edison Co.	EIX	51.06%	52.49%	50.17%	49.71%	49.48%	50.18%	50.59%	50.66%
Cleveland Electric Illuminating Company	FE	38.44%	38.19%	39.85%	39.41%	40.44%	42.28%	42.81%	42.24%
Jersey Central Power & Light Company	FE	51.52%	52.88%	56.05%	54.80%	56.51%	56.83%	55.74%	53.44%
Metropolitan Edison Company	FE	44.87%	45.77%	46.53%	46.64%	45.18%	45.00%	43.45%	42.43%
Monongahela Power Company	FE	48.10%	43.40%	45.86%	46.13%	45.29%	43.96%	45.76%	41.18%
Ohio Edison Company	FE	42.12%	40.91%	42.65%	42.09%	41.67%	40.81%	42.58%	40.91%
Pennsylvania Electric Company	FE	43.20%	44.29%	43.19%	41.96%	40.54%	44.47%	41.84%	40.34%
Pennsylvania Power Company	FE	60.21%	60.80%	60.92%	60.25%	59.48%	58.75%	59.55%	62.36%
Potomac Edison Company	FE	46.94%	46.49%	47.78%	46.41%	45.22%	43.97%	43.69%	41.08%
Toledo Edison Company	FE	37.22%	36.80%	38.02%	37.30%	36.88%	37.22%	38.81%	37.93%
West Penn Power Company	FE	48.00%	51.23%	51.70%	48.37%	47.57%	48.71%	50.98%	48.35%
Kansas City Power & Light Company	GXP	46.97%	47.99%	49.36%	47.51%	48.21%	48.69%	49.71%	48.08%
KCP&L Greater Missouri Operations Compar	GXP	53.21%	54.00%	54.19%	47.22%	50.04%	51.45%	51.77%	50.29%
Hawaiian Electric Company, Inc.	HE	54.77%	55.61%	54.16%	53.82%	55.99%	57.77%	56.66%	56.59%
Idaho Power Co.	IDA	51.30%	51.39%	51.53%	50.21%	50.88%	50.59%	50.44%	48.95%
Madison Gas and Electric Company	MGEE	60.47%	60.38%	60.48%	59.67%	59.68%	59.19%	59.45%	59.02%
Florida Power & Light Company	NEE	58.66%	59.89%	58.69%	57.63%	57.32%	58.16%	59.12%	56.67%
Connecticut Light and Power Company	NU	47.74%	48.32%	47.38%	47.36%	48.16%	50.41%	50.38%	50.08%
NSTAR Electric Company	NU	54.19%	54.08%	54.20%	52.50%	54.64%	55.62%	56.23%	53.53%
Public Service Company of New Hampshire	NU	50.99%	50.13%	49.97%	48.89%	48.89%	50.10%	47.06%	49.99%
Western Massachusetts Electric Company	NU	48.82%	48.71%	44.00%	45.68%	46.93%	49.71%	48.94%	48.04%
NorthWestern Corporation	NWE	47.02%	44.22%	45.72%	46.54%	46.36%	44.49%	45.16%	45.75%
Atlantic City Electric Company	POM	38.46%	39.45%	39.61%	39.67%	41.03%	40.80%	40.66%	37.47%
Delmarva Power & Light Company	POM	47.67%	47.88%	48.19%	45.19%	46.00%	47.62%	48.76%	49.89%
Potomac Electric Power Company	POM	48.57%	45.96%	46.88%	46.99%	46.69%	48.21%	49.61%	48.98%
Pacific Gas and Electric Company	PCG	51.31%	50.50%	50.14%	49.41%	48.79%	47.24%	48.45%	47.95%
Arizona Public Service Company	PNW	55.84%	55.75%	56.30%	53.78%	52.76%	54.46%	52.06%	52.44%
Public Service Company of New Mexico	PNM	49.34%	50.35%	51.08%	48.68%	49.53%	48.61%	46.70%	45.64%
Portland General Electric Company	POR	51.78%	51.11%	49.74%	49.47%	49.37%	48.51%	47.90%	47.78%
Kentucky Utilities Company	PPL	59.57%	59.28%	60.24%	59.91%	59.94%	59.85%	59.86%	59.54%
Louisville Gas and Electric Company	PPL	61.15%	60.80%	61.93%	61.57%	61.45%	61.31%	61.39%	60.99%
PPL Electric Utilities Corporation	PPL	50.79%	51.15%	50.95%	49.56%	52.15%	52.18%	51.01%	53.40%
South Carolina Electric & Gas Co.	SCG	51.69%	50.51%	50.66%	50.03%	50.49%	51.64%	51.36%	50.86%
Alabama Power Company	SO	46.49%	46.59%	47.52%	46.81%	45.57%	46.53%	47.29%	46.71%

Dr. Woolridge's Proxy Group Capital Structure

Georgia Power Company	SO	48.21%	49.05%	49.60%	47.90%	48.51%	50.24%	51.93%	49.83%
Gulf Power Company	SO	46.80%	46.20%	48.35%	46.07%	46.72%	45.41%	47.06%	45.62%
Mississippi Power Company	SO	NA	48.71%	46.17%	45.88%	41.82%	43.83%	57.54%	55.99%
United Illuminating Company	UIL	49.30%	50.22%	49.61%	49.13%	43.07%	43.39%	45.88%	46.44%
Tucson Electric Power Company	UNS	40.97%	41.30%	41.31%	40.89%	41.13%	43.07%	44.00%	41.16%
UNS Electric, Inc.	UNS	51.80%	52.34%	51.78%	52.43%	51.66%	51.15%	50.55%	51.44%
Kansas Gas and Electric Company	WR	62.22%	62.02%	59.27%	58.30%	57.85%	57.55%	57.70%	56.77%
Westar Energy (KPL)	WR	56.78%	57.28%	58.65%	56.21%	58.54%	61.07%	58.04%	55.80%
Wisconsin Electric Power Company	WEC	56.82%	56.22%	60.28%	58.92%	56.03%	54.82%	56.97%	58.82%
Northern States Power Company - MN	XEL	53.06%	52.10%	52.32%	52.74%	53.07%	52.05%	52.27%	52.27%
Northern States Power Company - WI	XEL	52.97%	50.56%	52.56%	54.17%	54.63%	54.59%	56.86%	55.87%
Public Service Company of Colorado	XEL	55.62%	55.98%	52.38%	57.01%	56.87%	56.65%	56.64%	57.06%
Southwestern Public Service Company	XEL	52.06%	51.40%	50.61%	49.67%	50.50%	51.89%	52.27%	49.66%

Source: SNL Financial

Dr. Woolridge's Proxy Group Capital Structure

Average Operating Company Capital Structure

Company	Ticker	% Debt 2013Q1	2012Q4	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2	Average
ALLETE, Inc.	ALE	42.83%	44.44%	44.55%	40.61%	40.64%	43.83%	42.25%	41.08%	42.53%
Alliant Energy Corporation	LNT	48.79%	48.89%	46.67%	48.29%	48.22%	47.82%	47.70%	48.59%	48.12%
Ameren Corporation	AEE	45.32%	45.39%	44.73%	44.74%	44.62%	44.31%	43.45%	43.81%	44.55%
American Electric Power Co.	AEP	51.58%	51.83%	51.95%	52.33%	52.78%	51.03%	50.56%	52.00%	51.76%
Avista Corporation	AVA	51.36%	51.83%	50.34%	51.39%	51.09%	52.03%	51.35%	51.18%	51.32%
Black Hills Corporation	BKH	44.75%	44.36%	44.48%	45.00%	42.65%	43.43%	44.03%	44.70%	44.17%
Cleco Corp.	CNL	49.10%	49.71%	50.23%	51.09%	51.62%	51.92%	52.48%	52.25%	51.05%
CMS Energy Corporation	CMS	47.55%	49.43%	48.74%	46.82%	47.31%	49.81%	49.76%	50.82%	48.78%
Consolidated Edison, Inc.	ED	45.78%	46.02%	45.81%	46.95%	46.63%	46.55%	46.34%	46.69%	46.35%
Dominion Resources, Inc.	D	46.60%	46.12%	44.60%	46.62%	46.08%	46.99%	45.75%	47.08%	46.23%
DTE Energy Company	DTE	52.39%	51.54%	51.69%	53.57%	51.53%	51.38%	51.79%	52.60%	52.06%
Duke Energy Corporation	DUK	44.75%	45.27%	44.81%	45.96%	45.80%	45.67%	44.29%	42.83%	44.92%
Edison International	EIX	48.94%	47.51%	49.83%	50.29%	50.52%	49.82%	49.41%	49.34%	49.46%
FirstEnergy Corporation	FE	53.94%	53.92%	52.75%	53.66%	54.12%	53.80%	53.48%	54.97%	53.83%
Great Plains Energy Incorporated	GXP	49.91%	49.01%	48.23%	52.63%	50.87%	49.93%	49.26%	50.82%	50.08%
Hawaiian Electric Industries, Inc.	HE	45.23%	44.39%	45.84%	46.18%	44.01%	42.23%	43.34%	43.41%	44.33%
IDACORP, Inc.	IDA	48.70%	48.61%	48.47%	49.79%	49.12%	49.41%	49.56%	51.05%	49.34%
MGE Energy, Inc.	MGEE	39.53%	39.62%	39.52%	40.33%	40.32%	40.81%	40.55%	40.98%	40.21%
Nextera Energy	NEE	41.34%	40.11%	41.31%	42.37%	42.68%	41.84%	40.88%	43.33%	41.73%
Northeast Utilities	NU	49.57%	49.69%	51.11%	51.39%	50.34%	48.54%	49.35%	49.59%	49.95%
NorthWestern Corporation	NWE	52.98%	55.78%	54.28%	53.46%	53.64%	55.51%	54.84%	54.25%	54.34%
Pepco Holdings, Inc.	POM	55.10%	55.57%	55.11%	56.05%	55.43%	54.46%	53.66%	54.55%	54.99%
PG&E Corporation	PCG	48.69%	49.50%	49.86%	50.59%	51.21%	52.76%	51.55%	52.05%	50.78%
Pinnacle West Capital Gorp.	PNW	44.16%	44.25%	43.70%	46.22%	47.24%	45.54%	47.94%	47.56%	45.83%
PNM Resources, Inc.	PNM	50.66%	49.65%	48.92%	51.32%	50.47%	51.39%	53.30%	54.36%	51.26%
Portland General Electric Company	POR	48.22%	48.89%	50.26%	50.53%	50.63%	51.49%	52.10%	52.22%	50.54%
PPL Corporation	PPL	42.83%	42.92%	42.29%	42.99%	42.16%	42.22%	42.58%	42.02%	42.50%
SCANACorporation	SCG	48.31%	49.49%	49.34%	49.97%	49.51%	48.36%	48.64%	49.14%	49.09%
Southern Company	SO	52.83%	52.36%	52.09%	53.34%	54.35%	53.50%	49.04%	50.46%	52.25%
UIL Holdings Corporation	UIL	50.70%	49.78%	50.39%	50.87%	56.93%	56.61%	54.12%	53.56%	52.87%
UNS Energy Corp.	UNS	53.62%	53.18%	53.46%	53.34%	53.60%	52.89%	52.73%	53.70%	53.31%
Westar Energy, Inc.	WR	40.50%	40.35%	41.04%	42.74%	41.81%	40.69%	42.13%	43.71%	41.62%
Wisconsin Energy Corporation	WEC	43.18%	43.78%	39.72%	41.08%	43.97%	45.18%	43.03%	41.18%	42.64%
Xcel Energy Inc.	XEL	46.58%	47.49%	48.03%	46.60%	46.23%	46.20%	45.49%	46.28%	46.61%
									Minimum	40.21%
									Maximum	54.99%

Dr. Woolridge's Proxy Group Capital Structure
Operating Company Capital Structure

Operating Company	Parent	% Debt 2013Q1	2012Q4	2012Q3	2012Q2	2012Q1	2011Q4	2011Q3	2011Q2
ALLETE (Minnesota Power)	ALE	43.91%	44.70%	45.59%	42.57%	42.31%	43.08%	43.72%	41.90%
Superior Water, Light and Power Company	ALE	41.76%	44.17%	43.51%	38.65%	38.97%	44.58%	40.78%	40.26%
Interstate Power and Light Company	LNT	47.45%	48.55%	48.48%	50.52%	50.43%	49.49%	49.69%	51.03%
Wisconsin Power and Light Company	LNT	50.14%	49.23%	44.87%	46.07%	46.01%	46.15%	45.71%	46.16%
Ameren Illinois Company	AEE	42.07%	42.56%	41.75%	40.88%	40.81%	40.70%	40.19%	40.28%
Union Electric Company	AEE	48.58%	48.23%	47.71%	48.61%	48.42%	47.92%	46.70%	47.34%
AEP Texas Central Company	AEP	54.02%	53.16%	52.33%	53.03%	54.22%	37.39%	39.16%	52.74%
AEP Texas North Company	AEP	55.98%	55.58%	55.32%	55.57%	55.19%	54.75%	54.74%	56.26%
Appalachian Power Company	AEP	55.27%	55.94%	55.96%	56.37%	56.59%	57.20%	55.81%	56.86%
Indiana Michigan Power Company	AEP	53.12%	50.41%	50.39%	50.58%	50.45%	50.87%	50.90%	51.36%
Kentucky Power Company	AEP	53.33%	53.98%	53.54%	53.88%	54.24%	54.39%	54.38%	54.58%
Kingsport Power Company	AEP	57.04%	55.49%	55.40%	52.58%	51.42%	51.73%	52.74%	49.13%
Ohio Power Company	AEP	45.08%	46.23%	45.62%	46.06%	46.51%	47.88%	46.08%	45.66%
Public Service Company of Oklahoma	AEP	51.53%	50.90%	50.31%	51.07%	51.60%	51.48%	51.44%	52.49%
Southwestern Electric Power Company	AEP	49.46%	49.20%	49.58%	50.73%	51.45%	50.04%	48.62%	49.68%
Wheeling Power Company	AEP	40.97%	47.41%	51.05%	53.46%	56.16%	54.56%	51.70%	51.28%
Avista Corporation	AVA	51.36%	51.83%	50.34%	51.39%	51.09%	52.03%	51.35%	51.18%
Black Hills Power, Inc.	BKH	45.37%	45.80%	46.28%	46.93%	44.07%	45.10%	45.62%	46.42%
Cheyenne Light, Fuel and Power Company	BKH	44.14%	42.91%	42.67%	43.08%	41.23%	41.77%	42.44%	42.97%
Cleco Power LLC	CNL	49.10%	49.71%	50.23%	51.09%	51.62%	51.92%	52.48%	52.25%
Consumers Energy Company	CMS	47.55%	49.43%	48.74%	46.82%	47.31%	49.81%	49.76%	50.82%
Consolidated Edison Company of New York, Inc.	ED	49.30%	49.31%	49.14%	51.48%	49.56%	48.81%	48.88%	49.33%
Orange and Rockland Utilities, Inc.	ED	51.22%	51.31%	51.25%	51.99%	52.13%	52.97%	52.04%	52.66%
Pike County Light and Power Company	ED	36.82%	37.43%	37.05%	37.37%	38.20%	37.87%	38.11%	38.08%
Virginia Electric and Power Company	D	46.60%	46.12%	44.60%	46.62%	46.08%	46.99%	45.75%	47.08%
DTE Electric Company	DTE	52.39%	51.54%	51.69%	53.57%	51.53%	51.38%	51.79%	52.60%
Duke Energy Carolinas, LLC	DUK	46.26%	46.87%	47.88%	46.08%	46.62%	49.43%	46.13%	46.96%
Duke Energy Florida, Inc.	DUK	50.18%	51.67%	49.26%	50.78%	50.74%	50.25%	48.59%	49.20%
Duke Energy Indiana, Inc.	DUK	49.61%	50.58%	50.77%	51.03%	51.99%	49.94%	48.43%	48.12%
Duke Energy Kentucky, Inc.	DUK	45.87%	47.10%	47.34%	47.00%	47.54%	48.34%	47.88%	40.49%
Duke Energy Ohio, Inc.	DUK	26.63%	25.80%	24.14%	29.29%	29.48%	29.66%	29.80%	29.21%
Duke Energy Progress, Inc.	DUK	49.93%	49.62%	49.45%	51.58%	48.44%	46.41%	44.89%	43.03%
Southern California Edison Co.	EIX	48.94%	47.51%	49.83%	50.29%	50.52%	49.82%	49.41%	49.34%
Cleveland Electric Illuminating Company	FE	61.56%	61.81%	60.15%	60.59%	59.56%	57.72%	57.19%	57.76%
Jersey Central Power & Light Company	FE	48.48%	47.12%	43.95%	45.20%	43.49%	43.17%	44.26%	46.56%
Metropolitan Edison Company	FE	55.13%	54.23%	53.47%	53.36%	54.82%	55.00%	56.55%	57.57%
Monongahela Power Company	FE	51.90%	56.60%	54.14%	53.87%	54.71%	56.04%	54.24%	58.82%
Ohio Edison Company	FE	57.88%	59.09%	57.35%	57.91%	58.33%	59.19%	57.42%	59.09%
Pennsylvania Electric Company	FE	56.80%	55.71%	56.81%	58.04%	59.46%	55.53%	58.16%	59.66%
Pennsylvania Power Company	FE	39.79%	39.20%	39.08%	39.75%	40.52%	41.25%	40.45%	37.64%
Potomac Edison Company	FE	53.06%	53.51%	52.22%	53.59%	54.78%	56.03%	56.31%	58.92%
Toledo Edison Company	FE	62.78%	63.20%	61.98%	62.70%	63.12%	62.78%	61.19%	62.07%
West Penn Power Company	FE	52.00%	48.77%	48.30%	51.63%	52.43%	51.29%	49.02%	51.65%
Kansas City Power & Light Company	GXP	53.03%	52.01%	50.64%	52.49%	51.79%	51.31%	50.29%	51.92%
KCP&L Greater Missouri Operations Company	GXP	46.79%	46.00%	45.81%	52.78%	49.96%	48.55%	48.23%	49.71%
Hawaiian Electric Company, Inc.	HE	45.23%	44.39%	45.84%	46.18%	44.01%	42.23%	43.34%	43.41%
Idaho Power Co.	IDA	48.70%	48.61%	48.47%	49.79%	49.12%	49.41%	49.56%	51.05%
Madison Gas and Electric Company	MGEE	39.53%	39.62%	39.52%	40.33%	40.32%	40.81%	40.55%	40.98%
Florida Power & Light Company	NEE	41.34%	40.11%	41.31%	42.37%	42.68%	41.84%	40.88%	43.33%
Connecticut Light and Power Company	NU	52.26%	51.68%	52.62%	52.64%	51.84%	49.59%	49.62%	49.92%
NSTAR Electric Company	NU	45.81%	45.92%	45.80%	47.50%	45.36%	44.38%	43.77%	46.47%
Public Service Company of New Hampshire	NU	49.01%	49.87%	50.03%	51.11%	51.11%	49.90%	52.94%	50.01%
Western Massachusetts Electric Company	NU	51.18%	51.29%	56.00%	54.32%	53.07%	50.29%	51.06%	51.96%
NorthWestern Corporation	NWE	52.98%	55.78%	54.28%	53.46%	53.64%	55.51%	54.84%	54.25%
Atlantic City Electric Company	POM	61.54%	60.55%	60.39%	60.33%	58.97%	59.20%	59.34%	62.53%
Delmarva Power & Light Company	POM	52.33%	52.12%	51.81%	54.81%	54.00%	52.38%	51.24%	50.11%
Potomac Electric Power Company	POM	51.43%	54.04%	53.12%	53.01%	53.31%	51.79%	50.39%	51.02%
Pacific Gas and Electric Company	PCG	48.69%	49.50%	49.86%	50.59%	51.21%	52.76%	51.55%	52.05%
Arizona Public Service Company	PNW	44.16%	44.25%	43.70%	46.22%	47.24%	45.54%	47.94%	47.56%
Public Service Company of New Mexico	PNM	50.66%	49.65%	48.92%	51.32%	50.47%	51.39%	53.30%	54.36%
Portland General Electric Company	POR	48.22%	48.89%	50.26%	50.53%	50.63%	51.49%	52.10%	52.22%
Kentucky Utilities Company	PPL	40.43%	40.72%	39.76%	40.09%	40.06%	40.15%	40.14%	40.46%
Louisville Gas and Electric Company	PPL	38.85%	39.20%	38.07%	38.43%	38.55%	38.69%	38.61%	39.01%
PPL Electric Utilities Corporation	PPL	49.21%	48.85%	49.05%	50.44%	47.85%	47.82%	48.99%	46.60%
South Carolina Electric & Gas Co.	SCG	48.31%	49.49%	49.34%	49.97%	49.51%	48.36%	48.64%	49.14%
Alabama Power Company	SO	53.51%	53.41%	52.48%	53.19%	54.43%	53.47%	52.71%	53.29%

Dr. Woolridge's Proxy Group Capital Structure

Georgia Power Company	SO	51.79%	50.95%	50.40%	52.10%	51.49%	49.76%	48.07%	50.17%
Gulf Power Company	SO	53.20%	53.80%	51.65%	53.93%	53.28%	54.59%	52.94%	54.38%
Mississippi Power Company	SO	NA	51.29%	53.83%	54.12%	58.18%	56.17%	42.46%	44.01%
United Illuminating Company	UIL	50.70%	49.78%	50.39%	50.87%	56.93%	56.61%	54.12%	53.56%
Tucson Electric Power Company	UNS	59.03%	58.70%	58.69%	59.11%	58.87%	56.93%	56.00%	58.84%
UNS Electric, Inc.	UNS	48.20%	47.66%	48.22%	47.57%	48.34%	48.85%	49.45%	48.56%
Kansas Gas and Electric Company	WR	37.78%	37.98%	40.73%	41.70%	42.15%	42.45%	42.30%	43.23%
Westar Energy (KPL)	WR	43.22%	42.72%	41.35%	43.79%	41.46%	38.93%	41.96%	44.20%
Wisconsin Electric Power Company	WEC	43.18%	43.78%	39.72%	41.08%	43.97%	45.18%	43.03%	41.18%
Northern States Power Company - MN	XEL	46.94%	47.90%	47.68%	47.26%	46.93%	47.95%	47.73%	47.73%
Northern States Power Company - WI	XEL	47.03%	49.44%	47.44%	45.83%	45.37%	45.41%	43.14%	44.13%
Public Service Company of Colorado	XEL	44.38%	44.02%	47.62%	42.99%	43.13%	43.35%	43.36%	42.94%
Southwestern Public Service Company	XEL	47.94%	48.60%	49.39%	50.33%	49.50%	48.11%	47.73%	50.34%

Source: SNL Financial

2012 - 2013 Reported Authorized Returns on Equity, Electric Utility Rate Cases

State [1]	Docket [1]	Utility [1]	Authorized ROE [1]	Decision Date [1]	Vertically Integrated ("V") or T&D ("D") [2]	S&P Credit Supportive Ranking [3]	Vertically Integrated ROE
SC	D-2011-271-E	Duke Energy Carolinas LLC	10.50%	1/25/2012	V	4	10.50%
NC	D-E-7, Sub 989	Duke Energy Carolinas LLC	10.50%	1/27/2012	V	3	10.50%
MI	C-U-16801	Indiana Michigan Power Co.	10.20%	2/15/2012	V	4	10.20%
OR	D-UE-233	Idaho Power Co.	9.90%	2/23/2012	V	3	9.90%
FL	D-110138-EI	Gulf Power Co.	10.25%	2/27/2012	V	3	10.25%
ND	C-PU-10-657	Northern States Power Co. - ND	10.40%	2/29/2012	V	3	10.40%
MN	D-E-002/GR-10-971	Northern States Power Co. - MN	10.37%	3/29/2012	V	3	10.37%
HI	D-2009-0164	Hawaii Electric Light Co	10.00%	4/4/2012	V	2	10.00%
CO	D-11AL-947E	Public Service Co. of CO	10.00%	4/26/2012	V	3	10.00%
HI	D-2009-0163	Maui Electric Company Ltd	10.00%	5/2/2012	V	2	10.00%
WA	D-UE-111048	Puget Sound Energy Inc.	9.80%	5/7/2012	V	2	9.80%
AZ	D-E-01345A-11-0224	Arizona Public Service Co.	10.00%	5/15/2012	V	2	10.00%
IL	D-11-0721	Commonwealth Edison Co.	10.05%	5/29/2012	D	2	
MI	C-U-16794	Consumers Energy Co.	10.30%	6/7/2012	V	4	10.30%
NY	C-11-E-0408	Orange & Rockland Utlts Inc.	9.40%	6/14/2012	D	2	
WI	D-6680-UR-118 (elec)	Wisconsin Power and Light Co.	10.40%	6/15/2012	V	4	10.40%
WY	D-20003-114-ER-11 (elec)	Cheyenne Light Fuel Power Co.	9.60%	6/18/2012	V	2	9.60%
SD	D-EL11-019	Northern States Power Co. - ND	9.25%	6/19/2012	V	3	9.25%
MI	C-U-16830	Wisconsin Electric Power Co.	10.10%	6/26/2012	V	4	10.10%
HI	D-2009-0080	Hawaiian Electric Co.	10.00%	6/29/2012	V	2	10.00%
OK	Ca-PUD201100087	Oklahoma Gas and Electric Co.	10.20%	7/9/2012	V	3	10.20%
WY	D-20000-405-ER-11	PacifiCorp (Rocky Mountain Power)	9.80%	7/16/2012	V	2	9.80%
MD	C-9285	Delmarva Power & Light Co.	9.81%	7/20/2012	D	2	
MD	C-9286	Potomac Electric Power Co.	9.31%	7/20/2012	D	2	
TX	D-39896	Entergy Texas Inc.	9.80%	9/13/2012	V	2	9.80%
IL	D-12-0001	Ameren Illinois	10.05%	9/19/2012	D	2	
UT	D-11-035-200	PacifiCorp (Rocky Mountain Power)	9.80%	9/19/2012	V	2	9.80%
DC	FC-1087	Potomac Electric Power Co.	9.50%	9/26/2012	D	1	
NJ	D-ER-11080469	Atlantic City Electric Co.	9.75%	10/23/2012	D	3	
WI	D-6690-UR-121 (Elec)	Wisconsin Public Service Corp.	10.30%	10/24/2012	V	4	10.30%
WI	D-3270-UR-118 (elec)	Madison Gas and Electric Co.	10.30%	11/9/2012	V	4	10.30%
WI	D-05-UR-106 (WEP-Elec)	Wisconsin Electric Power Co.	10.40%	11/28/2012	V	4	10.40%
CA	A-12-02-014	California Pacific Electric Co	9.88%	11/29/2012	V	4	9.88%
DE	D-11-528	Delmarva Power & Light Co.	9.75%	11/29/2012	D	1	
IL	D-12-0293	Ameren Illinois	9.71%	12/5/2012	D	2	
PA	D-R-2012-2290597	PPL Electric Utilities Corp.	10.40%	12/5/2012	D	3	
MO	C-ER-2012-0166	Union Electric Co.	9.80%	12/12/2012	V	2	9.80%
FL	D-120015-EI	Florida Power & Light Co.	10.50%	12/13/2012	V	3	10.50%
KS	D-12-KCPE-764-RTS	Kansas City Power & Light	9.50%	12/13/2012	V	3	9.50%
WI	D-4220-UR-118 (elec)	Northern States Power Co - WI	10.40%	12/14/2012	V	4	10.40%
IL	D-12-0321	Commonwealth Edison Co.	9.71%	12/19/2012	D	2	
SC	D-2012-218-E	South Carolina Electric & Gas	10.25%	12/19/2012	V	4	10.25%
CA	Ap-12-04-018 (Elec)	Pacific Gas and Electric Co.	10.40%	12/20/2012	V	4	10.40%
CA	Ap-12-04-016 (Elec)	San Diego Gas & Electric Co.	10.30%	12/20/2012	V	4	10.30%
CA	Ap-12-04-015	Southern California Edison Co.	10.45%	12/20/2012	V	4	10.45%
KY	C-2012-00221	Kentucky Utilities Co.	10.25%	12/20/2012	V	3	10.25%
KY	C-2012-00222 (elec.)	Louisville Gas & Electric Co.	10.25%	12/20/2012	V	3	10.25%
OR	D-UE-246	Pacificorp	9.80%	12/20/2012	V	3	9.80%
RI	4323	Narragansett Electric Co.	9.50%	12/20/2012	D	2	
NC	D-E-22, Sub 479	Virginia Electric & Power Co.	10.20%	12/21/2012	V	3	10.20%
WA	D-UE-120436	Avista Corp.	9.80%	12/26/2012	V	2	9.80%
MO	ER-2012-0174	Kansas City Power & Light	9.70%	1/9/2013	V	2	9.70%
MO	ER-2012-0175	KCP&L Greater Missouri Op Co.	9.70%	1/9/2013	V	2	9.70%
IN	44075	Indiana Michigan Power Co.	10.20%	2/13/2013	V	3	10.20%
MD	9299	Baltimore Gas and Electric Co.	9.75%	2/22/2013	D	2	
LA	U-32220	Southwestern Electric Power Co.	10.00%	2/27/2013	V	3	10.00%
NY	12-E-0201	Niagara Mohawk Power Corp.	9.30%	3/14/2013	D	2	
ID	AVU-E-12-08	Avista Corp.	9.80%	3/27/2013	V	3	9.80%
OH	12-1682-EL-AIR	Duke Energy Ohio Inc.	9.84%	5/1/2013	D	3	
MI	U-17087	Consumers Energy Co.	10.30%	5/15/2013	V	4	10.30%
NC	E-2, Sub 1023	Duke Energy Progress Inc.	10.20%	5/30/2013	V	3	10.20%
HI	2011-0092	Maui Electric Company Ltd	9.00%	5/31/2013	V	2	9.00%
AZ	E-01933A-12-0291	Tucson Electric Power Co.	10.00%	6/11/2013	V	2	10.00%
NJ	ER-12121071	Atlantic City Electric Co.	9.75%	6/21/2013	D	3	
WA	UE-130137	Puget Sound Energy Inc.	9.80%	6/25/2013	V	2	9.80%
		Average	9.97%				10.05%
		Median	10.00%				10.10%
		Minimum	9.00%				9.00%
		Maximum	10.50%				10.50%

State [1]	Docket [1]	Utility [1]	Authorized ROE [1]	Decision Date [1]	Vertically Integrated ("V") or T&D ("D") [2]	S&P Credit Supportive Ranking [3]	Vertically Integrated ROE

Vertically Integrated Companies:

S&P Ranking	S&P Score	Median Authorized ROE
More Credit Supportive	4	10.30%
Credit Supportive	3	10.20%
Less Credit Supportive	2	9.80%
Least Credit Supportive	1	NA
Credit Supportive + More	3 & 4	10.25%

Count of Vertically Integrated Authorized ROEs 10.20% or above: 24
Count of Vertically Integrated Authorized ROEs below 10.20%: 25

[1] Sources: Exhibit SWC-3 and Regulatory Research Associates
[2] Source: Regulatory Research Associates, *Electric Industry Restructuring: Tier Redefinition and Update,* August, 1 2012. "Tier 1" restructuring states considered T&D.
[3] Source: Standard & Poor's, *Standard & Poor's Revises Its U.S. Utility Regulatory Assessments,* December 28, 2012.

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT
OF
LORRAINE L.CIFUENTES

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

LORRAINE L. CIFUENTES

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

A. My name is Lorraine L. Cifuentes. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as manager of Load Research and Forecasting.

Q. Are you the same Lorraine L. Cifuentes who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors and shortcomings in the prepared direct testimony of witness Michael P. Gorman, testifying on behalf of Federal Executive Agencies ("FEA") and Donna Ramas, testifying on behalf of the Office of Public Counsel ("OPC").

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes, I have. My Exhibit No.__ (LLC-2), consisting of five documents, was prepared by me or under my direction and supervision. These consist of:

Document No. 1	Residential Average Consumption from 2005-2012 and Projected 2013-2014
Document No. 2	Residential Energy Sales and Economic Growth
Document No. 3	Total Energy Sales and Economic Growth
Document No. 4	2012 Degree Days versus Normal
Document NO. 5	Witness Gorman's Proposed Methodology Revised to Include 2012

Q. Please summarize the key concerns and disagreements you have regarding the substance of witness Gorman's and witness Ramas' testimony.

A. My key concerns and disagreements are as follows:

1. I disagree with witness Gorman's assessment that Tampa Electric has understated the amount of energy sales and revenues for the 2014 test year. Specifically, witness Gorman's use of the 2005 to

2012 average residential sales per customer as the basis for computing a 14.25 MWH projected annual sales per customer in the 2014 test year is not appropriate.

2. I disagree with witness Gorman's opinion that projected sales use per customer in 2014 is inconsistent with the explanatory assumptions and data outlined in my direct testimony and is not consistent with conditions utilities like Tampa Electric are experiencing in the real world.

3. I disagree with witness Gorman's statement that the 2014 load characteristics appear to be rather pessimistic given the level of heating and cooling degree days used for estimating residential sales use per customer in 2014.

4. I disagree with witness Gorman's assertion that the 2005 to 2012 historical average of 14.87 MWH sales per customer is skewed downward by 2012 data.

5. Concerning witness Ramas's testimony, if an adjustment to industrial revenues is made as she suggests, a corresponding adjustment downward for the projected decrease in commercial base revenues should also be made.

2014 RESIDENTIAL SALES PER CUSTOMER

Q. What is the residential sales revenue for 2014 at present rates forecasted by Tampa Electric?

A. Tampa Electric has forecasted 2014 residential sales revenue to be $489.6 million based on residential energy sales of 8,563,003 MWH.

Q. Is the 2014 residential revenue at present rates projected by Tampa Electric reasonable?

A. Yes. Tampa Electric projected a reasonable level of residential sales revenue at present rates based on the assumptions outlined in my direct testimony and supported in the direct testimony of witness Eric Fox on behalf of Tampa Electric Company.

Q. Is the 2014 residential revenue at present rates projected by witness Gorman reasonable?

A. No. Witness Gorman erroneously suggests that the residential class's 2014 base revenues are understated by $12.5 million at present rates. His methodology for arriving at projected revenues for 2014 overlooks important facts, has severe shortcomings and is

inaccurate.

Q. Please describe these shortcomings.

A. Using the 2005 to 2012 historical average of 14.87 MWH residential sales per customer as the basis to project 2014 residential energy sales and revenues is not appropriate or reasonable. This methodology ignores the impacts that weather, economic conditions, improvements in appliance/lighting efficiencies and conservation have had on residential consumption per customer during the period between 2005 and 2012 and the impacts that these factors will have in 2013 and 2014.

During 2005 to 2012, residential sales per customer declined by an average of 1.1 percent a year and they declined an average of 1.2 percent a year on a weather normalized basis. Taking into account the factors that witness Gorman overlooks in his analysis the correct projection of 2014 sales per residential customer should be approximately 13.86 MWH. Document No. 1 of my exhibit compares witness Gorman's projection of 2014 residential sales per customer to Tampa Electric's projection. From this comparison, it is clear that witness Gorman's 14.25 MWH is out of line with the historical trend and is

unreasonable.

Q. Is witness Gorman's forecast consistent with the company's recent actual experience?

A. No. Document No. 1 of my exhibit also shows the company's most current (as of June 2013) projections for year-end 2013 and 2014. As can be seen from the graph, 2013 weather normalized sales, which includes six months of actual results, is performing slightly below budget. This means that the forecast the company used for its 2014 test year slightly overstates expected revenues - not the opposite as suggested by witness Gorman.

Q. Is it a common forecasting practice to use historical averages as the basis for projecting per customer electricity consumption?

A. No. It is not common or accepted forecasting practice to project sales per customer by applying an adjustment to a historical average. I am not aware of any utility in Florida that estimates future per customer electricity consumption in that manner.

Q. How do you know that other Florida utilities do not use

historical averages to project future electricity consumption?

A. As chairman of the Florida Reliability Coordinating Council's ("FRCC") Load Forecasting Working Group, I facilitate the annual forecast methodology review workshop. Each FRCC member utility presents their load forecast models, assumptions and forecast results. During the workshops held annually from 2008 to present, there has not been a single utility that presented a per customer consumption model that was based on historical averages.

Q. How has the economy impacted residential sales per customer during 2005-2012?

A. The economic downturn that began in 2007 and the resulting high unemployment rate has impacted the income levels of many households, forcing many of them to find ways to cut discretionary expenses such as electricity consumption. Economy-induced conservation has contributed to the declining trend in sales per customer; however, this trend is not accurately reflected in witness Gorman's analysis of 2014 sales per customer.

Q. How have improved appliance and lighting efficiencies impacted residential sales per customer during 2005 to 2012?

A. As stated in my direct testimony, appliance efficiency standards that have been put in place over the past few years are primarily responsible for the significant changes in energy consumption patterns across the electric utility industry. These standards will continue to put downward pressure on growth as new and more efficient appliances and lighting are added to replace existing stock.

In 2012, a new lighting standard from the U.S. Department of Energy went into effect. As of January 2012, the traditional 100 watt incandescent light bulb will not meet the energy efficiency standards and will no longer be available at most stores. Similar standards will be phased in for the 75 watt bulbs in 2013 and for the 60 and 40 watt bulbs in 2014.

To illustrate the impact that lighting alone has on residential base revenues, assume that each of the company's 613,000 residential customers replace one 75 watt incandescent light bulb with a compact florescent

light bulb ("CFL"). This would result in an energy savings of 0.5 percent for each customer and a reduction in the company's residential base revenues of approximately $2 million a year. If each residential customer replaces 10 bulbs, the estimated energy savings per customer is almost 5.0 percent a year and a reduction in the company's residential base revenues of $20 million a year.

Witness Gorman's analysis fails to consider the effect of the new energy efficiency standards on energy consumption; however, these effects are clearly showing in the company's actual results.

Q. Are there any other factors that witness Gorman excludes from his analysis that would contribute to lower sales per customer in 2014?

A. Yes, there are several other factors. There has been a strong emphasis by many organizations, including electric companies, on the benefits of conserving energy and that has started to resonate with customers particularly during the economic downturn. It is not realistic to assume that consumers will abandon what they have learned about conservation and reverse their behavior as the economy

improves. Energy conservation habits will be a permanent behavioral change for many.

Changing customer mix and the lower energy intensity of new residential customers will also put downward pressure on the overall residential system average sales per customer. New homes use less energy due to mandated federal energy efficiency guidelines and state building codes that encourage more energy efficiency. In addition to this, recent data shows most of the new customers requesting electric service are living in multi-family units which on average use just over half of the amount of electricity that a single-family home uses.

All these factors and conditions are real, are occurring in the company's service territory and will continue to put downward pressure on sales per customer. A new customer today will consume less energy than the average customer on the system and this will have a downward effect on average customer usage. Witness Gorman's failure to consider these factors makes his estimate inappropriate for use in this proceeding.

Q. Does Tampa Electric's residential sales per customer forecast reflect the improvement in economic conditions

and the increased efficiency of appliances and lighting?

A. Yes. Unlike witness Gorman's calculation of 2014 sales per customer, the company's forecasting models take into account the primary drivers that impact per customer electricity consumption. MFR Schedules F-6, F-7 and F-8 provide a description and values associated with the assumptions used in the development of the 2014 test year residential energy sales.

Q. How accurate is the projection for this year's residential sales per customer?

A. Year to date, residential sales per customer are 2.8 percent below budget, in part due to milder winter weather. Removing the impacts of weather, normalized sales per customer are 1.4 percent below budget. This suggests that the company's 2014 forecast is probably slightly overstated, which in turn understates the company's revenue requirement in 2014.

Q. Does the company have a more recent forecast of residential sales per customer than the forecast presented in this proceeding?

A. Yes. In June of 2013 the annual forecast process was completed. Combining six months of actuals and six months of updated projections for 2013, year-end residential sales per customer are 13.83 MWH. This is 0.6 percent lower than the forecast for 2013 presented in my direct testimony and the MFRs.

Tampa Electric's most current projection for 2014 of 13.81 MWH is 0.4 percent lower than the forecast present in my rebuttal testimony. Document No. 1 of my exhibit shows the most current forecasts compared to the forecast presented in my direct testimony. From this graph, it is evident that 2013 sales per customer declined as initially projected. This confirms that the projections for 2014, although slightly higher than the company's recently completed projections, are still reasonable, unlike witness Gorman's projection.

EXPLANITORY ASSUMPTIONS

Q. Do you agree with witness Gorman's assertion that projected electrical usage per customer in 2014 is inconsistent with the explanatory data outlined in your direct testimony?

A. No. The per-customer consumption projected for 2014 is

very consistent with data outlined in my direct testimony. Witness Gorman only discusses economic assumptions and suggests that future residential sales per customer should follow a similar trend. Witness Gorman's observations ignore the other significant drivers, mentioned above, that have contributed to the downward trend in sales per customer.

Q. Do you agree with witness Gorman, that the projected economic activity for the Tampa Electric service territory is quite robust for the 2014 test year relative to the historical period 2009 to 2012?

A. No. Although the economy is showing signs of improvement, the recovery can hardly be called robust. Moreover, witness Gorman is incorrect in assuming residential per customer usage should be equal to or more robust in the 2014 test year relative to the historical period 2009 to 2012.

Q. Do you agree with witness Gorman that the economic assumptions for the 2014 test year indicate that customers are going to be spending more on discretionary items such as electricity?

A. There is a relationship between the economy and electricity sales, but recent trends show that the relationship has been changing; residential sales per customer are not growing with the economy as they have in the past. Document No. 8 of witness Gorman's exhibit shows the relationship between gross domestic product and energy sales from 1988 to 2009. However, the graph ignores 2010, 2011 and 2012 and therefore, fails to show how this relationship has been changing in recent years. As such, witness Gorman's suggested correlation is no longer accurate.

In an effort to supply the data for 2010 through 2012 that witness Gorman omitted from his Document No. 8, Document Nos. 2 and 3 of my exhibit show the correlation between Tampa Electric's residential energy sales and household income and between Gross Regional Product and total energy sales. The historical trends from 1994 to 2009 show a strong correlation, however, by 2010 and through the present it becomes evident that this relationship is changing and is no longer as strong as it once was.

Q. Why is this trend changing?

A. Economic growth has been outpacing electricity consumption

in recent years due to changes in customer consumption patterns brought on by the economy and increasing efficiencies for lighting and appliances. This phenomenon has diminished the correlation between economic growth and electricity consumption. As a result, a sharp rebound in electricity demand is not expected, even if the economy continues to improve.

HEATING AND COOLING DEGREE DAYS

Q. Do you agree with witness Gorman that the 2014 load characteristics appear to be rather pessimistic?

A. No. As explained below, witness Gorman is incorrect in suggesting that the projected level of heating degree-days ("HDD") and cooling degree-days ("CDD") likely explains the projected decline in average use per residential customer.

Q. Do you agree with witness Gorman that you have not adequately justified the lowering of heating and cooling degree days used for estimating residential energy sales in 2014?

A. No. The lower HDD and CDD that witness Gorman is referring to are the results of Monte Carlo simulations

using actual HDD and CDD over the most recent 20 year period. They will not exactly equal the 20 year average because the Monte Carlo simulation produces results that are probabilistic in nature.

Q. Are normal degree-days updated every year with the company's forecasting process?

A. Yes. The most current 20 year period is always used, which means the oldest year drops off and the most current year is added to the period for determining normal degree-days.

Q. What is the impact on residential base revenues if the 20 year average of 515 HDD and 3,667 CDD are used in 2014, rather than the Monte Carlo results?

A. Using the actual 20 year averages of 515 HDD and 3,667 CDD to project residential energy sales for 2014, the impact on base revenues is less than $1 million. Since normal degree-days are based on a rolling 20 year period, it is not uncommon for normal degree-days to fluctuate up or down from year to year resulting in insignificant increases or decreases in base revenues.

IMPACT OF 2012 ON THE 2005-2012 HISTORICAL AVERAGE

Q. Do you agree with witness Gorman that the 2005 to 2012 historical average of 14.87 MWH is skewed downward by 2012 data, which reflects weak economic activity, and abnormally low heating degree days?

A. No. Witness Gorman states that "2012 did not reflect normal residential heating loads". He goes on to discuss that as a result, 2012 residential consumption was abnormally low and skews the 2005 to 2012 average downward. What witness Gorman failed to mention was the offsetting effect that higher than normal cooling appliance loads had on the results.

March of 2012 had CDD that were more than double the normal levels and CDD in April of 2012 were higher than they have been in over 25 years. This hotter than normal weather resulted in more energy sales which contributed to offsetting most of the energy sales lost during the winter months. Document No. 4 of my exhibit shows actual 2012 degree-days compared to normal degree-days. In total, the degree-days for the year were not abnormal. In addition, Document No. 1 of my exhibit shows that actual 2012 sales were not significantly different when weather adjusted. In 2012, weather reduced residential sales per customer by

only 0.8 percent.

Also, witness Gorman fails to point out that the year 2010 was one of the coldest winters on record. 2010 has the greatest impact on skewing the average, and 2010 skews the average up, not down. The extreme weather in 2010 increased residential sales per customer by 7.6 percent. Document No. 1 of my exhibit shows the significant difference in actual and weather normalized sales per customer in 2010.

Q. Was witness Gorman's exclusion of 2012 data from his adjustment to the 2005 to 2012 historical average justified?

A. No. Given that 2012 was not abnormal as witness Gorman suggests, if witness Gorman's calculation was revised to include the year 2012, his estimate of sales per customer for 2014 would be 13.51 MWH, even lower than the company's estimate of 13.86 MWH for 2014. Table 1 and 2 in Document No. 5 of my exhibit show a comparison of witness Gorman's proposed calculation and the revised calculation including 2012. If the calculation made by witness Gorman is updated to include 2012, then witness Gorman would be proposing that the residential base revenues for 2014 as

filed by Tampa Electric should be reduced by $9.7 million, not increased by $12.5 million as his testimony proposes.

Witness Gorman's failure to take into account both the heating and cooling impacts that Tampa Electric experienced in 2012 invalidates his recommended exclusion of 2012 data.

INDUSTRIAL REVENUES

Q. Do you agree with witness Ramas' proposed adjustment to industrial revenues of $35,000 for stronger customer growth in the General Service rate class in 2012 than expected?

A. No. While there was a slight increase in the Industrial General Service rate class revenues there were also offsetting decrease in the commercial revenues. As such, if any adjustment should be made it would be a net downward adjustment to revenues.

INFLATION FACTORS USED IN THE 2014 TEST YEAR BUDGET

Q. How is Tampa Electric's inflation assumption, which is used in its operations and maintenance ("O&M") budget, developed?

A. Tampa Electric uses the Consumer Price Index ("CPI") projections provided by Moody's Analytics, a leading provider of economic forecasting services, in developing its inflation forecast for budgeting purposes. CPI is the most widely utilized indicator of changes in the price of goods and services. MFR Schedules C-33 and C-40 provide historical and projected annual percent changes in CPI. I provided Moody's projected CPI values as a guide in the development of the projected 2014 test year O&M budget.

Q. What are the appropriate inflation factors for use in forecasting the test year budget?

A. The appropriate inflation factors for use in forecasting the 2014 test year budget are a CPI of 240.7 and an annual CPI percentage increase of 2.7. A variety of other price indices, that better reflect the costs related to specific products or services, were also used in the budgeting process.

Q. What are the most current CPI inflation forecasts for 2013 and 2014 as projected by Moody's Analytics?

A. The most current CPI projections for 2013 and 2014 are 232.9 and 237.4, respectively, or a 1.9 percent annual

increase.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. Tampa Electric's estimate of 2014 residential energy sales per customer and base revenues are appropriate and reasonable. This year's average sales per customer continued to decline as projected, which means that the company's projections for 2014 are still reasonable. Updated forecasts show residential sales per customer that are 0.4 percent lower in 2014, which is not much different than the forecast presented in my direct testimony. Based on these current trends, it would be inappropriate and unreasonable to expect that 2014 sales per customer would sharply rebound to a level higher than those experienced during the past three years. For this reason, I disagree with witness Gorman's analysis and proposed increase in residential base revenues of $12.5 million.

Also, while the number of industrial customers is slightly above budget, commercial customers are below budget by a greater amount. Growth in the commercial sector is still sluggish and offsets any upside in the industrial sector. Based on this current trend, the company does not agree

with witness Ramas' proposed adjustment to industrial revenues of $35,000 for stronger customer growth in the industrial General Service rate class.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
WITNESS: CIFUENTES

EXHIBIT

OF

LORRAINE L.CIFUENTES

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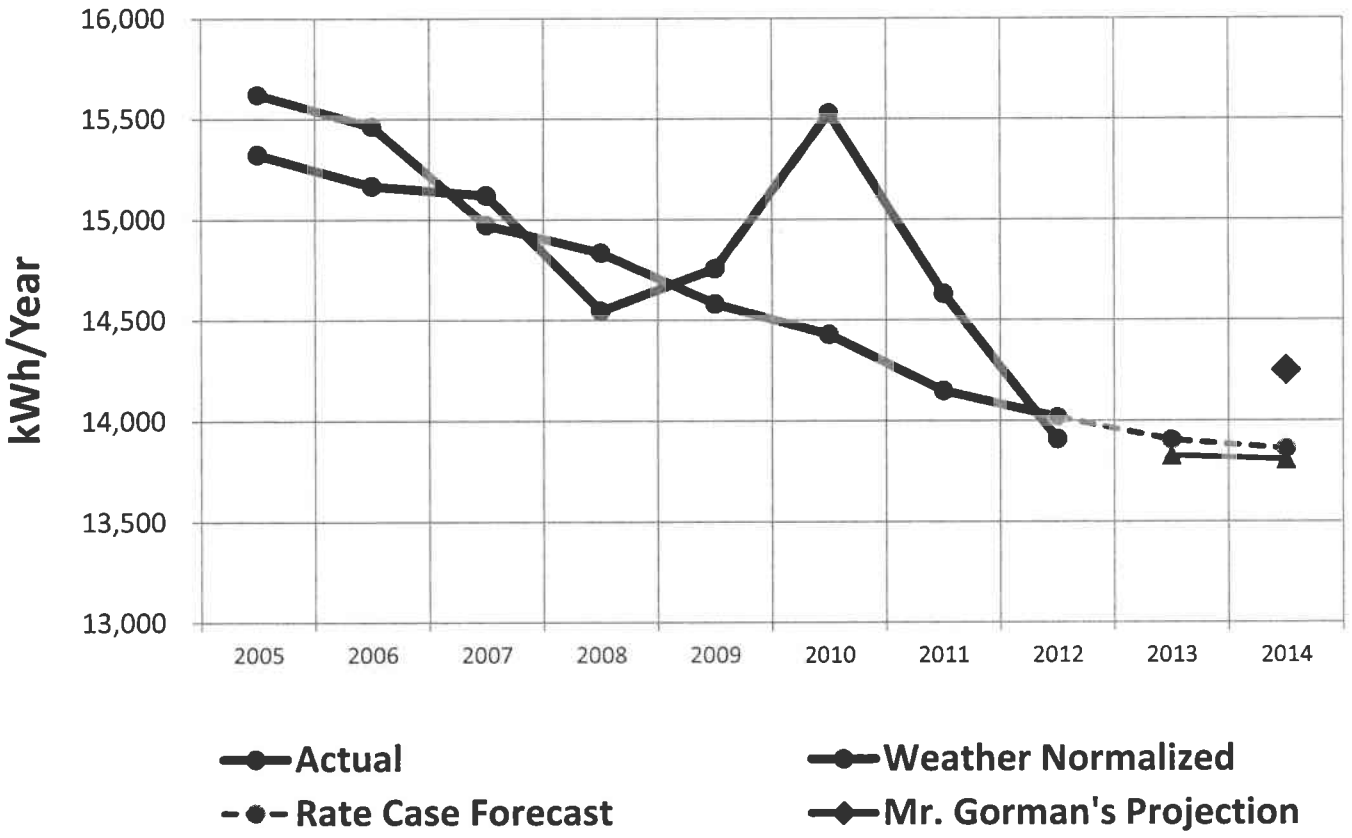
Residential Average Consumption



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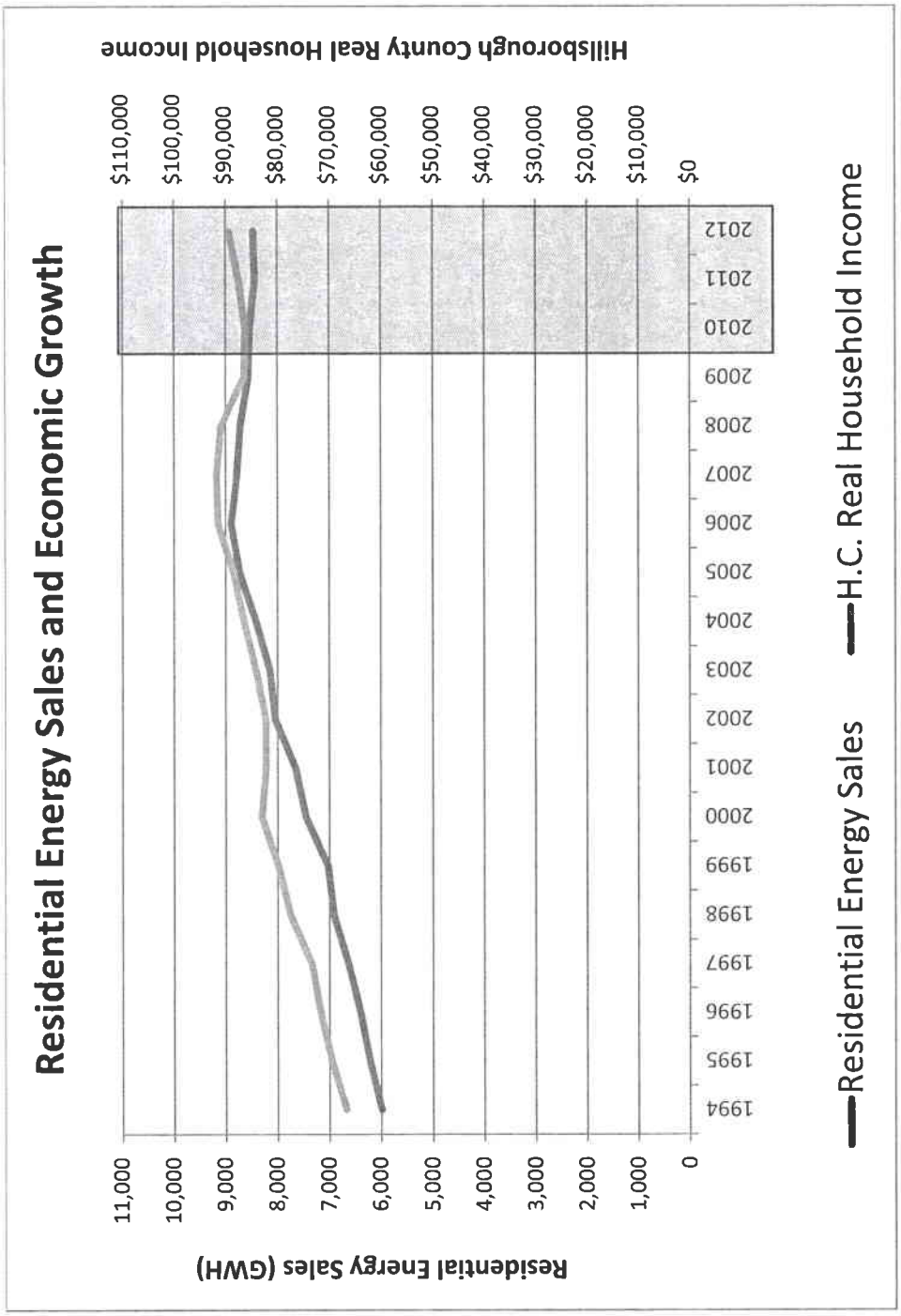

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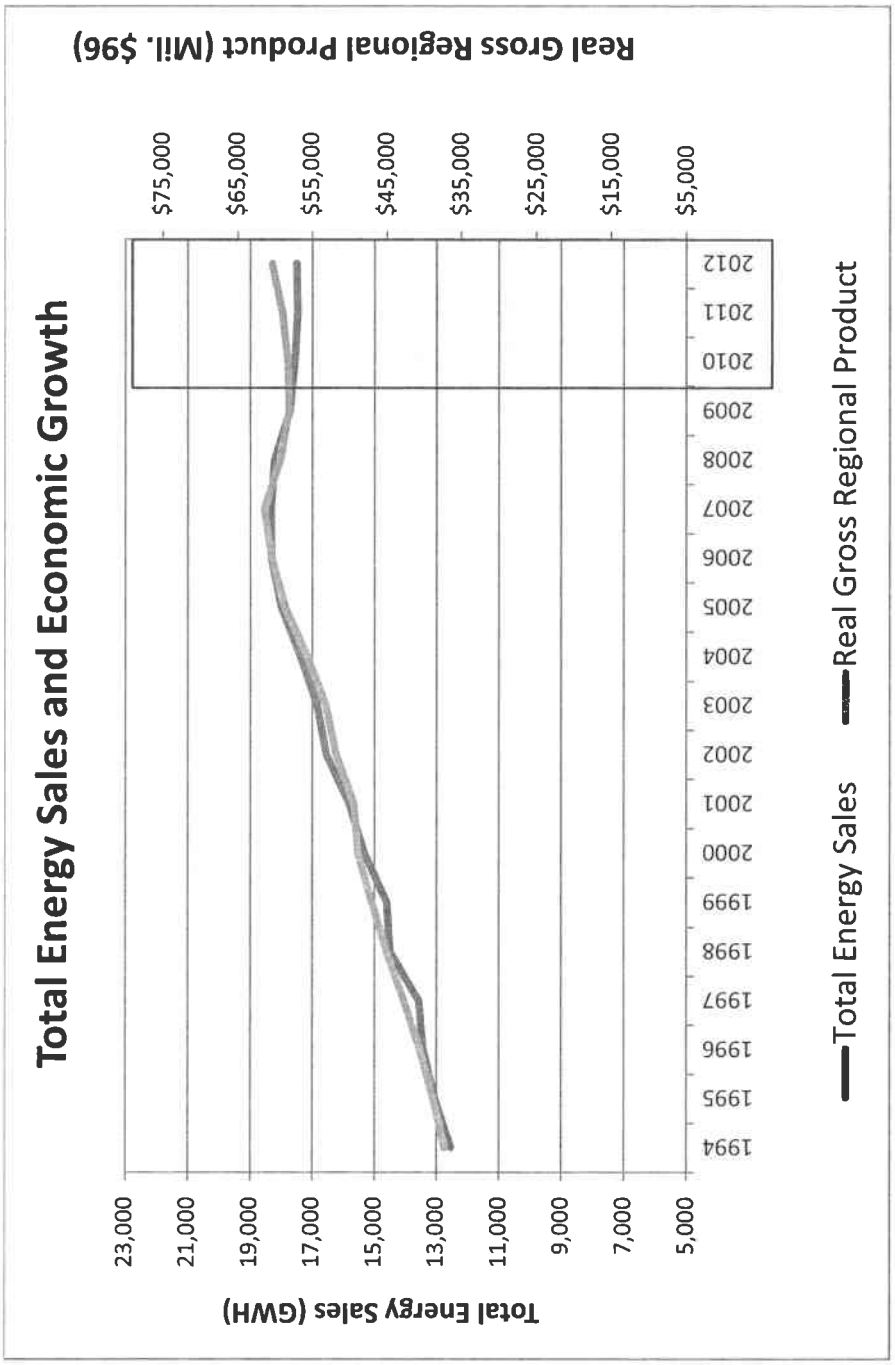

2012 Degree Days Versus Normal

	Heating Degree Days	Cooling Degree Days	Total Degree Days
2012	241	3916	4157
Normal	512	3655	4167
Variance	-271	261	-10

Table 1
Witness Gorman's Proposed Methodology

	TEC Residential MWh/Customer	%Change	Cumulative %Change
2005	15.32		
2006	15.16	-1.0%	-1.0%
2007	15.12	-0.3%	-1.3%
2008	14.54	-3.8%	-5.1%
2009	14.75	1.4%	-3.7%
2010	15.53	5.2%	1.6%
2011	14.63	-5.8%	-4.2%
2012	13.91		
Average	14.87		

Mr. Gorman's Adjustment to Historical Average:
14.87 x (100% - 4.2%) = 14.25

Tampa Electric's 2014 MWh/Cutomer:
13.86

Table 2
Witness Gorman's Proposed Methodology
Modified to Include 2012

	TEC Residential MWh/Customer	%Change	Cumulative %Change
2005	15.32		
2006	15.16	-1.0%	-1.0%
2007	15.12	-0.3%	-1.3%
2008	14.54	-3.8%	-5.1%
2009	14.75	1.4%	-3.7%
2010	15.53	5.2%	1.6%
2011	14.63	-5.8%	-4.2%
2012	13.91	-4.9%	-9.1%
Average	14.87		

Mr. Gorman's Revised Calculation:
14.87 x (100% - 9.1%) = 13.51

Tampa Electric's 2014 MWh/Cutomer:
13.86

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT
OF
MARK J. HORNICK

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

MARK J. HORNICK

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

A. My name is Mark J. Hornick. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director of Engineering and Project Management.

Q. Are you the same Mark J. Hornick who filed direct testimony in this proceeding?

A. Yes, I am.

Q. Have you prepared an exhibit to accompany your rebuttal testimony?

A. Yes. My Exhibit No.__ (MJH-2), consisting of one document entitled "Planned Major Outages in Weeks, 2007-2020" was prepared by me or under my direction and supervision.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors and shortcomings in the prepared direct testimonies of witness Helmuth W. Schultz, III testifying on behalf of the Office of Public Counsel ("OPC"), witness Jeffery Pollock, testifying on behalf of the Florida Industrial Power Users' Group ("FIPUG"), and witness Lane Kollen, testifying on behalf of the WCF Hospital Utility Alliance ("HUA"). In so doing, I explain why the Commission should not make any negative adjustments to Tampa Electric's requested level of generation maintenance expense.

Q. Please summarize the testimony of witnesses Schultz, Pollock and Kollen regarding Tampa Electric's proposed level of generation maintenance expense for the 2014 projected test year.

A. Each of these three witnesses states that Tampa Electric's $17.585 million planned outage maintenance expense for the 2014 test year is higher than previous actual expenses and recommends a reduction in the allowed amount. Witness Schultz calculates a five year average of planned outage expense for the period 2008 through 2012, and after adjusting for inflation, he recommends a

reduction of $4.088 million. Witness Pollock calculates a seven year average expense for each unit excluding peakers for the years 2008 through 2014 and recommends a reduction of $3.665 million. Witness Kollen proposes a $7.145 million reduction based on his calculated three year average expense during 2010 through 2012. The positions taken by the three witnesses are summarized in the following table:

Witness	Comparison	Recommended Reduction	Inflation Adjustment
Pollock	7 year avg. (2009-2014)	$3.665 million	No
Schultz	5 year avg. (2008-2012)	$4.088 million	Yes
Kollen	3 year avg. (2010-2012)	$7.145 million	No

Q. Do you agree with the intervenor witnesses' proposed adjustments to test year generation maintenance expenses?

A. No. Each of the reductions recommended by intervenor witnesses was prepared using a simplistic accounting approach rather than an engineering analysis. These three witnesses use historical maintenance spending to judge the reasonableness of Tampa Electric's proposed generation maintenance expense for the 2014 test year. I, and the other Tampa Electric witnesses, have clearly explained in direct testimony that the company

intentionally reduced its spending during the last few years because of revenue shortfalls. Tampa Electric eliminated or deferred needed maintenance activities to prudently manage the business and defer the need to request a base rate increase, to the benefit of customers. The intervenor witnesses now attempt to use these abnormally low historical spending levels to suggest that the 2014 test year generation operation and maintenance ("O&M") expense is abnormally high. If the Commission adopts this approach, the company will find itself in a position where "no good deed goes unpunished," and Tampa Electric will be forced to continue its austerity spending levels, to the detriment of customers. As I stated in my direct testimony, the company is beginning to see the effects of reduced maintenance spending on unit performance and availability.

More importantly, each of the intervenor witnesses who proposes an adjustment to 2014 generation maintenance expense failed to consider the maintenance needs for Tampa Electric's power plants. Although I described the types of maintenance activities that the company needs to perform in 2014 in my direct testimony and discovery responses, the intervenor witnesses did not identify any

specific item of maintenance activity that the company should not perform.

Q. Do you have a specific concern with the way witness Kollen calculated his proposed adjustment?

A. Yes. Witness Kollen focuses only on the most recent three year actual expenses and did not adjust his historical average to recognize the effect of inflation. By failing to consider the effects of inflation, witness Kollen compounds the problem caused by his improper reliance on historical averages and proposes an adjustment that is unrealistic and unjustified.

Q. Do you agree with the approach used by witness Schultz to calculate his proposed adjustment?

A. No. Witness Schultz computes a historical average using five years of historical generation maintenance expense information and adjusts his average for inflation. Witness Schultz focuses on the period 2008 through 2012 and averages the expense levels, including the deliberately restricted spending during 2010 through 2012, to calculate an inflation adjusted average value of $13.497 million. He proposes an adjustment for the

difference between this amount and the $17.585 million proposed by the company for 2014, or $4.088 million.

Witness Schultz makes the same mistake that witness Kollen made, looking backward at accounting data rather than looking forward and focusing on engineering analysis, compliance, environmental and safety needs and operating plans.

Based on the work Tampa Electric must complete, including catching up on deferred maintenance items for the next several years, and as explained in the company's answer to OPC's Fifth Set of Interrogatories, No. 77, Tampa Electric's generation planned outage maintenance expense is $18.030 million and $17.450 million for 2015 and 2016, respectively. Compared to the levels of generation expense that Tampa Electric expects to incur in 2015 and 2016, the company's proposed 2014 planned outage generation maintenance expense, $17.585 million, is reasonable. Tampa Electric must return to a sustainable level of maintenance spending for its generating units, not continue to maintain the restricted levels necessitated by revenue shortfalls in previous years. The level of 2014 spending proposed by witness Schultz would result in continued suppression of needed maintenance

activities at the company's power plants and could result in the deterioration of generating unit performance.

Q. Do you agree with the negative adjustment proposed by witness Pollock?

A. No. Witness Pollock also erroneously uses a backward-looking accounting approach to evaluate the 2014 level of planned outage generation maintenance expense; and he fails to identify any particular maintenance item that the company should not perform in 2014. He computes his average using expense amounts for the years 2008 through 2014. He also excludes peaking units from his analysis, which unreasonably removes $285,000 planned maintenance expense for work on five aero-derivative combustion turbines ("CT") that were installed in 2009 and are beginning to need maintenance. In fact, the company now projects that the planned maintenance cost for these units will be higher than the $285,000 included in the test year expenses. Witness Pollock also does not perform an adjustment for inflation in his analysis. There is no rational basis to exclude the peaking units from his calculation or to ignore the effects of inflation.

Q. Is the 2014 level of spending for generation planned

maintenance, by unit, unusual or out of the ordinary?

A. No, not at all. The planned maintenance major outage expenses for Big Bend Unit 1 and Big Bend Unit 4 are budgeted at $5.4 million and $5.7 million, respectively. In 2006, the actual planned maintenance expenses for the Big Bend Unit 1 outage was $4.0 million. In 2007, the actual planned maintenance expense for Big Bend Unit 4 was $6.4 million. The projected spending for the 2014 planned major outages on these units represents a typical level needed for sustainable operating performance, as can be seen by comparing the planned expenses to the aforementioned actual major planned outage expenses for the same units.

Q. Is it unusual to have two major planned outages planned in any given year?

A. No. Tampa Electric's 2014 outage plan is a typical plan that is driven by the maintenance needs of each unit and the power demands of our customers. Major outages, which are typically eight weeks in duration, require a significant amount of long-range planning and coordination. The large coal units at Big Bend Power Station are typically on a three- to four-year major

outage cycle. With the current level of utilization, Bayside Units 1 and 2 require a major outage every four years, driven by CT manufacturer's guidelines. Polk Unit 1 is typically on a three-year major outage cycle, driven by both CT and gasifier maintenance requirements.

Document No. 1 of my exhibit shows actual and planned major outages from 2007 through 2020; the average number of planned major outages for this period is 2.2 annually. The test year is a typical year, with two major planned outages during 2014. In fact, there are three major outages planned in 2015, the year following the test year, and Tampa Electric's budgeted maintenance expense for 2015 is $18.030 million.

Q. Please describe any other relevant measures by which the Commission should judge the prudence and reasonableness of Tampa Electric's generation planned outage expenses.

A. The Commission evaluated Tampa Electric's 2009 test year planned maintenance expenses during the company's last base rate proceeding. In the Final Order No. PSC-09-0283-FOF-EI, issued on April 30, 2009 in Docket No. 080317-EI, the Commission reduced the company's planned outage expense from $20.2 million to $17.35 million, and stated

that this amount was a "justified level for the test year" (at page 59). The Commission-approved 2009 planned outage generation maintenance expense is in line with the 2014 test year expense of $17.585 million, not taking into account that the company's generating fleet is older now than it was in 2009. After considering the effects of inflation, Tampa Electric's planned outage generation maintenance expense for 2014 is $1.95 million below the level approved for 2009 in the course of the company's last base rate proceeding.

Q. What activities will Tampa Electric have to forego or defer if the Commission accepts an intervenor proposal to reduce the company's proposed level of planned generation maintenance expense for the 2014 test year?

A. If its allowed level of planned generation maintenance spending is reduced, then Tampa Electric will have to prioritize needed activities by judging which items have a lower risk of adverse impacts if deferred. Known problem areas would be high priority items for work to be completed. On the other hand, equipment inspections, such as inspecting the steam turbine on Big Bend Unit 1, which is planned for Fall 2014 and for which approximately $3 million is included in 2014 test year expense, would have

to be evaluated for deferral.

Steam turbine inspections are long duration activities that are typically on the critical path timeline for an outage and involve substantial expense. Deferring the inspection would require a re-evaluation of the unit major outage schedule and likely would postpone that outage to the following year, with cascading effects to other planned maintenance. Other work scheduled to be performed during that outage, such as boiler tube replacements, boiler feed pump maintenance and the generator rewind would also be postponed. The overall impact of these deferrals of critical work would be detrimental to the performance of the generating units. If work of this type is not completed during planned outages, an equipment failure while the unit is in service would require corrective maintenance during a forced outage, and that is less efficient and more costly than doing the work in a pre-planned manner. For these reasons, reducing the company's requested generation maintenance expense would present significant challenges to the company and may result in additional costs to both customers and the company. The adjustments to generation maintenance expense, as proposed by the intervenor witnesses, should not be made.

Q. Has Tampa Electric been faced with similar decisions to eliminate or defer work to manage expense levels and have there been negative impacts?

A. Yes. As described throughout the company's filing in the instant docket, Tampa Electric had to reduce spending in several areas due to revenue shortfalls following its last base rate case. A representative list of deferred generating unit maintenance was supplied in the company's response to OPC's Fifth Set of Interrogatories, No. 71. One of the items deferred in 2012 was the $3.5 million Big Bend Unit 3 steam turbine inspection. Due to this deferral, the major outage schedule was re-evaluated, and the Big Bend Unit 3 turbine inspection and associated major outage work were rescheduled to 2013. In this case, the steam turbine performed acceptably during the deferred inspection period from 2012 to the spring of 2013. However, if the Big Bend Unit 1 steam turbine inspection and associated outage work is deferred in 2014, Tampa Electric will experience increased risk of not only steam turbine problems, but also boiler tube failures, generator issues and high energy piping integrity concerns. As I stated in my direct testimony, Tampa Electric is beginning to see signs that further deferral of planned maintenance activities will decrease

unit performance and availability. This is why the company is so concerned about the adjustments to generation maintenance expenses proposed by the intervenors.

Q. Are there any other areas where you disagree with the conclusions reached by witness Schultz?

A. Yes. Witness Schultz has raised issues concerning the company's proposed headcount and staffing. Witness Register addresses these issues in detail from a company-wide perspective in his rebuttal testimony. I disagree with witness Schultz to the extent he asserts that the proposed test year headcount for Energy Supply is unreasonable.

Q. Are headcount changes proposed in the Energy Supply area from 2012 to the 2014 test year?

A. Yes. There are 21 new Energy Supply positions to be added during the 2012 to 2014 timeframe.

Q. What are the reasons these new positions are needed?

A. There are two main drivers for the position additions.

First, the company is actively working to design and construct the Polk 2-5 Combined Cycle Conversion Project. This is a very large project taking place over several years and will require over 1.5 million man-hours of work. It is clearly not practical or prudent to add permanent staff to cover this activity, and the majority of the work will be completed by contractors. However, seven permanent positions are required to work almost exclusively on the Polk 2-5 Combined Cycle Conversion Project. These seven positions are engineering, technical and administrative positions that are needed to oversee the design and construction of the facility. The positions will ensure that the work is done properly, that the project is on schedule and on budget and that the generating unit will meet the needs of customers. Additionally, these seven positions will have very little impact on O&M expense levels since the majority of the employees' time will be charged to capital project accounts.

The second reason that new positions are needed in Energy Supply is the construction of the water treatment facility at the Polk Power Station. In order to successfully treat the wastewater from Lakeland to meet the water quality needs of the Polk Power Station, the

new treatment plant is large and complex. The wastewater contains substantial amounts of suspended and dissolved solids, including algae from the Lakeland wetlands treatment system. The dissolved solids will be removed by a combination of a large clarifier/ reactor, with associated chemical injection, solids dewatering and multimedia filtration. The water will then be directed to large reverse osmosis assemblies for removal of dissolved solids. The concentrated effluent from the reverse osmosis units will be collected, chemically treated and passed through a final filter before being injected into the two deep disposal wells at the Polk site. The clean permeate from the reverse osmosis units will be collected and distributed for use in the Polk Power Station.

The operation and maintenance of the remote pumping station, waste water pipeline and the water treatment equipment are all new activities beginning in the test year. Tampa Electric must periodically check the pump station and pipeline for proper operation and integrity. The company must carefully monitor and control water flow rates through the system and chemical additions and dispose of solids that are removed from the system. Tampa Electric must operate and maintain the instrumentation, controls, electrical distribution systems, motors and

pumps for the new water treatment system. The company has evaluated these manpower requirements and has considered synergies with the existing workforce at Polk Power Station. While existing staff can complete some of this work, the company expects that at least 13 new positions will be required. This includes two full time operating personnel on each of the five operating teams, along with supervision and technical support. These 13 positions are included in the company's test year expenses, and it is possible that incremental staff positions beyond these 13 will be needed.

The remaining position addition in Energy Supply is for an engineer in the Planning, Strategy and Compliance Department. This position is needed to handle the new workload associated with expanded NERC/CIP reliability standards compliance.

Q. Based on the foregoing, should any adjustments be made to Tampa Electric's requested level of generation expense for the 2014 projected test year?

A. No. Tampa Electric's proposed level of generation operation and maintenance expense of $138.8 million for the 2014 projected test year is reasonable. This expense

level is based on the company's best engineering judgment regarding the levels of operation and maintenance activities needed at its power plants in 2014. This amount reflects a reasonable and appropriate level of planned outage expenses of $17.585 million and increased staffing levels to accomplish new activities and the company's maintenance plans for 2014. The proposed amount is also reasonable in light of Tampa Electric's plans for 2015 and 2016.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony points out the serious errors and shortcomings in the testimony of witnesses Schultz, Pollock and Kollen. These witnesses used a backward looking historical spending approach to attempt to determine the appropriate level of generation planned outage maintenance expense for the company's 2014 test year expense. This "accounting style" method gives no consideration to the condition of the generating units and the real needs for maintenance spending to reasonably ensure continued safety, compliance with regulations and acceptable operating performance. Their conclusions also ignore the fact that the company intentionally reduced spending in recent years and instead recommend the

continuation of non-sustainable funding levels. None of the intervenor witnesses' recommendations are appropriate, and their adjustments to generation O&M expense should not be applied.

My rebuttal testimony also describes the new Energy Supply positions the company will add within the 2014 test year. Each of the 21 positions is associated with new and necessary activities that are incremental to the prior test year.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
WITNESS: HORNICK

EXHIBIT

OF

MARK J. HORNICK

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TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
EXHIBIT NO. ___ (MJH-2)
WITNESS: HORNICK
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Planned Major Outages in Weeks
2007 - 2020

Year	No. of Weeks								No. of Major Outages
	BB1	BB2	BB3	BB4	BPS1	BPS2	PK1	PK2	
2007			6.2	12.8					2
2008		5.4	16.9			7.0			3
2009	5.5	13.8					7.1		3
2010	15.6			10.1					2
2011		8.9			10.3				2
2012						8.8	6.6		2
2013			11.2				8.0		2
2014	10.0			8.0					2
2015		8.0			8.0		5.0		3
2016			8.0			8.0			2
2017				8.0					1
2018	8.0						5.0		2
2019		8.0			8.0				2
2020			8.0			8.0		4.0	3

Notes:
2007 - 2013 - Actual
2014 - 2020 - Projected
BB - Big Bend Station
BPS - Bayside Power Station
PK - Polk Power Station

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TAMPA ELECTRIC

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COMMISSION
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT
OF
S. BETH YOUNG

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

S. BETH YOUNG

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

A. My name is S. Beth Young. My business address is 820 S. 78th Street, Tampa, Florida 33619. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Transmission.

Q. Are you the same S. Beth Young who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors and shortcomings in the prepared direct testimony of witness Lane Kollen, testifying on behalf of the WCF Hospital Utility Alliance ("HUA"); and witnesses Helmuth W. Schultz, III and Donna Ramas, testifying on behalf of

the Office of Public Counsel ("OPC").

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes, I have. My Exhibit No.__ (SBY-2), consisting of two documents, was prepared by me or under my direction and supervision. These consist of:

Document No. 1	Distribution O&M Expense
Document No. 2	2012 Tree Trim Analysis

Q. Please explain the key concerns and disagreements you have regarding the substance of witness Shultz's testimony concerning headcount.

A. The conclusions in witness Schultz's testimony are incorrect due to fundamental flaws in his methods.

The first flaw is that his headcount analysis is done in isolation. There is no consideration for other factors that impact what the needed headcount should be, such as the actual work that needs to be done, system growth, customer growth, and maintenance and replacement needs due to age of infrastructure.

The second flaw involves witness Schultz's attempt to determine future headcount needs based on historical staffing levels. Rather than looking backwards, projected staffing needs ("headcount") should be determined based on workload requirements in the future.

The third flaw is witness Schultz's failure to consider all relevant factors when conducting his headcount analysis. Determining the appropriate headcount for workload requires a complete labor analysis, including but not limited to the following considerations: how many journeyman positions are needed, how much overtime is required at projected staffing levels, how to prepare for future journeymen retirements, and how many contractors are needed. Tampa Electric balances these factors in determining the appropriate headcount. Witness Schultz's recommendations will lead to greater labor expenses and an inability to provide adequate customer service because he does not consider all of these factors in his headcount recommendation. As a result of these flaws, the Commission should reject witness Schultz's proposed headcount adjustment.

Q. Do you agree with witness Schultz's point that an average annual compensation increase of approximately 3 percent

is appropriate?

A. Yes.

Q. Witness Schultz states that the company has not provided sufficient support or justification for additional employees in 2013 and 2014. Do you agree with his assessment?

A. No. Tampa Electric explained its plans to hire additional employees in its answers and responses to discovery sent by OPC and the Staff. The company included 46 new positions in the Transmission and Distribution areas in 2013 and 2014. Twenty-three of those positions have already been filled. All of these 46 new positions in the Transmission and Distribution organization are needed due to new activities and the incremental workload described below and to prepare for future journeymen retirements. I have described below the new activity or incremental work for each of the positions.

Apprentice Linemen (32 positions)

During the 2014 test year, Tampa Electric projects additional O&M and capital work compared to 2012. This incremental work consists of system expansion due to an

increase in new customer work, pole replacements, government-mandated relocations and distribution line maintenance. The workforce needed to complete this construction work consists of line contractors, linemen, and apprentice linemen. During the apprentice program, apprentice linemen work with line crews to develop the skills necessary to be become linemen. In doing so, apprentice linemen improve the productivity of line crews because they can complete the tasks that do not require as much skill, and the linemen can apply their higher level skillsets to higher level tasks.

The labor expense for the incremental capital work is approximately $8.1 million. Apprentice Linemen represent approximately $1.12 million of this labor expense; and the remainder of the $8.1 million is represented by a combination of Tampa Electric internal labor and contractor labor. There is also an O&M component of the Apprentice Linemen labor expenses. Apprentices work on distribution line maintenance projects and attend training, safety meetings, and informational meetings, and the test year O&M expense impact for these activities is approximately $330,000.

Cable Splicers (2 positions)

The Cable Splicer position is a specialized position that works on Tampa Electric's Network System, which provides reliable service to downtown Tampa. The company has one Network crew that conducts scheduled maintenance, replaces failed cables, installs lines to new customer load and re-works lines for building renovations and road construction work. These two new positions are needed because of increased work that the Network crew will face during the test year period. Eight new high rise buildings are planned or are in preliminary stages of construction in downtown Tampa, and renovations are planned for three additional buildings, requiring the underground lines to be re-worked.

In addition to the projects I already described, Tampa Electric's Network crew will be facing an increased level of work to replace 1950's vintage network promwtors that are at the end of their useful lives. This additional work is necessary in order to avoid significant outages and maintain appropriate service levels to the company's customers. Tampa Electric is also aware of additional line relocations needed for incremental road projects and incremental cable replacements above normal workload levels. The new hires in this area will allow the company to complete this incremental work in a safe, efficient and

cost-effective manner.

Smart Grid Engineer & Radio Electrician (2 Positions)

Tampa Electric's Volt/VAR Program allows the company to use new communication infrastructure to provide real-time management of distribution capacitors. This program ensures a consistent voltage profile and will save approximately $1 million annually in fuel costs due to reduced system energy losses. The company must add one smart grid engineer position and one radio technician position to implement and maintain the Volt/VAR program. The new smart grid engineer will provide project management support during the installation of the Volt/VAR program and then oversee the communication system for optimal performance. The radio electrician will maintain the communication system and respond to any failures.

Relay Specialist (1 position)

This position is responsible for testing relays that protect both the public, the NERC-defined Bulk Electric System, and the Tampa Electric system. This work helps to ensure system integrity and to prevent damage to expensive power equipment. To complete the company's ongoing testing plan, Tampa Electric expects that the number of tests performed will increase by 32.9 percent in

the test year. Tampa Electric currently employs three Relay Specialists; adding an additional position will increase the capacity and output of the group by 33.3 percent, which will enable the company to complete the ongoing testing plan and comply with NERC requirements.

DDT Training Administrator (1 position)

As part of the 2009 restructuring described in the testimony of witness Register, Tampa Electric combined two positions, the Environmental Coordinator and the Distribution Design Technician ("DDT") Trainer positions. One person has been struggling to do the work that was done by two previously. In addition, there has been an increase in capital work as noted above in my testimony. This increase applies to the DDT's, as well as the Linemen and Apprentice Linemen. The company has already filled the DDT Administrator position, and the employee spends part of her time in the classroom and the remaining time doing fieldwork due to increased capital work.

Substation Apprentices (8 positions)

The two main drivers requiring additional Substation Apprentices are increased workload to complete the Polk 2-5 Combined Cycle Conversion Project and the impact of aging infrastructure. The company is forecasting an almost

50 percent increase in Substation work above the current workload for the 2014 test year relating to the transmission component of the Polk 2-5 Combined Cycle Conversion Project and the impact of aging infrastructure. A portion of this work will be completed by substation contractors, and the remaining incremental work will be completed by the added Substation Apprentices.

Aging infrastructure has increased substation costs and created uncertainty of future costs. One example of this is the Substation Distribution Transformer fleet. In the 2009 test year, 11.5 percent of the transformers were over 40 years old; in the 2014 test year that percentage has grown to 20.8 percent. There has been an average of two transformer failures per year from 2002 to 2010. From 2011 to 2013, the failure rate has increased to an average of six failures per year. The replacement of these additional transformer failures is incremental work for the substation organization. In addition to the increased capital work of transformer replacements, there has also been an increase in O&M work to prevent failures of other aged units. The impact of aging infrastructure in substations is an ongoing need that will be met with additional Substation Electricians who are developed through the Substation Apprentice program.

Q. Since the company has a need for additional positions due to ongoing incremental work, why does the company think that filling those positions with apprentices is the best decision for the customers?

A. In order to provide reliable, safe, and cost effective service to customers, the Transmission and Distribution organization structures the assignment of work to be done by skilled craft positions in the following fashion. Base workload is performed by Tampa Electric journeyman positions, and those positions are supported by an ongoing apprenticeship program. Peak workload is performed by contracted journeyman positions. The value in having Tampa Electric journeyman positions perform the base workload comes from greater ownership, higher quality work and the ability to quickly respond to customer needs. Additionally, maintaining source diversity for the required workforce allows the company to take advantage of market forces that help minimize labor costs for these highly skilled workers.

Having an ongoing and consistent apprentice program is both prudent and effective from a workforce management perspective. The apprentices are able to produce results and prepare for an efficient transition when journeymen

retire in the future. Planning ahead for these retirements appropriately ensures that there is no decline in customer service levels. As part of a crew, apprentices enable journeyman to apply their higher level skills to high level work tasks while apprentices complete tasks that do not require as much skill. The apprentices also learn the higher level skills while working as part of a crew. This system results in improved productivity and reduces the overall per unit labor costs.

Q. Based on his assessment, witness Schultz questions whether new positions will actually be filled, at page 8 of his testimony. Are his assessments correct?

A. No. Witness Schultz actually contradicts himself on the same page when he describes 14 positions that have already been filled. However, even the 14 positions that witness Schultz admits have been filled is an incomplete view. Tampa Electric has identified a need for 26 new positions in Transmission and Distribution in 2013, and the company has already filled 23 of those positions. The remaining three for 2013 will be filled before the end of this year.

Q. On page 8 of his testimony, witness Schultz discusses the

historical size of the Apprentice Lineman Program as 11 participants. Is historical class size an effective way to determine what the class size for 2013 and 2014 should be?

A. No. This backward looking approach is a flawed way to determine appropriate class size. The appropriate method is to look at workload and the number of positions needed to complete the work and the forecast for future retirements. Tampa Electric first determined the minimum Apprentice Linemen class size based on future retirements of linemen, troublemen, system dispatchers, and operations supervisors. In addition, workload, as described earlier in my testimony was factored in and balanced with the use of contractors to finalize the class size.

Q. Please respond to witness Schultz's point on page 8 of his testimony where he claims that an initial class size of 20 resulted in only 14 Apprentice Linemen entering the program.

A. In reading witness Schultz's statement, it conflicts with his statement on page 9, where he states that the Apprentice Linemen class size is 16. Tampa Electric's 20-

position class is made up of an Apprentice Linemen class of 16 and a Substation Apprentice class of 4. Tampa Electric has hired 14 Apprentice Linemen and have completed filling the Substation Apprentice class.

DISTRIBUTION O&M EXPENSE

Q. Please summarize the key concerns and disagreements you have regarding the substance of witness Kollen's testimony concerning O&M Expense.

A. Witness Kollen bases his Distribution O&M expense recommendation on interrogatory responses that do not include all of the Distribution O&M expense accounts. Because he did not consider all of the relevant information, his recommendation is flawed. In addition, he has raised a "red herring" by stating the Storm Hardening program should result in "continuing and growing savings through the test year."

Q. Is Tampa Electric's requested level of Distribution O&M expense in the amount of $51,285,000 for the 2014 projected test year appropriate?

A. Yes. This level of expense is reasonable and appropriate in light of the workload and staffing levels expected in

2014 and will enable the company to provide safe and reliable electric service to its customers. As discussed below, this amount is well below the O&M benchmark for 2014.

Q. Do you agree with witness Kollen's assertion that the Distribution O&M Expense for the test year is excessive and not justified?

A. No. Tampa Electric has worked hard to prudently operate and maintain its distribution system in a cost-effective manner. One measure of this success is that the Distribution O&M expense is $6,482,000 below the benchmark. The level of expense is dictated by expected workload and corresponding expenses during the test year.

Q. Did Tampa Electric change its financial system in 2012 and were there any other changes made concurrently with this change?

A. Yes. Several of the variances between years and FERC accounts are related solely to this change. Prior to changing the company's financial system in 2012, all expense charges were reviewed to ensure they were being charged to the most appropriate FERC account. The result

was a shift among FERC expense accounts, changes in some activities being more appropriately charged to O&M expense instead of capital, and some changes in IT and Telecommunication allocation of expenses.

Q. Did this result in any changes in Distribution O&M expense?

A. Yes, it did. Document No. 1 of my exhibit, summarizes the major differences between the 2012 and 2014 test year budgets. First, the IT, Telecommunications and Facilities allocations were reviewed to ensure they were allocated appropriately, resulting in a modification of the allocation between transmission and distribution. The change is $1.806 million of IT and Telecommunications expense charged to distribution instead of transmission.

Second, Tampa Electric determined that the dispatcher switching time for capital projects, that had been charged to those capital projects, should be charged to FERC Account 581. Third, the Skills Training Center trainers' time for the Distribution area was previously split between capital and O&M expense, and Tampa Electric determined that it should be charged 100 percent to O&M expense. These changes resulted in an increase of

$475,000 in Distribution O&M Expense for the 2014 test year.

Q. When comparing the 2012 actuals to the test year, what other items make up the increase in the Distribution O&M Expense?

A. The rest of the increase in Distribution O&M Expense is attributable to several items, each of which is explained below.

The first item is the effect of inflation from 2012 to 2014. Tampa Electric used a 3 percent annual inflation adjustment.

The second item is expenses for new software system maintenance fees. There were no software maintenance fees in 2012 for the Outage Management System ("OMS") and the Volt/VAR program, and the fees for these programs are included in the test year expenses. The impact is an additional $388,000. The OMS system was upgraded in 2011, and the maintenance fees were covered through 2012 with the project. The Volt/VAR Program maintenance fees are for the communication system and the operating software. The communication system and the operating

software will be implemented in 2013, and the maintenance fees begin in 2014.

The third item is fleet charges. In 2012, when Tampa Electric implemented its new financial system, the fleet costs for the Meter Department were not being captured properly. The amount that was not accounted for in 2012 was $320,000, and this was corrected for the 2014 test year costs. In addition, the fleet allocation methodology was changed to follow labor at a higher department level. This resulted in a shift from capital to Distribution O&M Expense in the amount of $420,000.

The fourth item is pole loading analyses expenses. In 2012, Tampa Electric performed fewer pole loading analyses than prescribed in its Storm Hardening Plan. In 2014, the typical number of pole loading analyses is planned. The test year budget includes an additional $100,000 for this activity which is based on the typical amount of pole analysis for a year.

The fifth item is meter reclassification. In 2012, the remaining Automated Meter Reading Program meter replacements were completed. The meter additions in 2014 will be less, resulting in less capital meter work and an

increase of meter expense of $587,000.

The last addition is due to new positions. The increased workload described earlier in my testimony necessitated the addition of 46 positions above 2012 staffing levels. The test year impact on Distribution O&M Expense is $612,000. The reasons for the new positions are explained above.

Q. Witness Kollen asserts that the Storm Hardening program expenditures "result in continuing and growing savings through the test year." Do you agree?

A. No. Witness Kollen's statement fails to recognize the reality of how a T&D system operates. The Storm Hardening program was designed to strengthen and add resiliency to the T&D system, and it has also provided some reliability benefits on a day-to-day basis. The vegetation management program and the pole inspection program may potentially reduce some outage restoration O&M expense, but there are not "continuing and growing savings" that result from the Storm Hardening program. The value of the company's Storm Hardening program will be seen when a major storm hits the company's service area - via shorter restoration times and potentially less damage.

TREE TRIM EXPENSE

Q. Please summarize the key concerns and disagreements you have regarding the substance of witness Schultz's testimony concerning tree trimming.

A. His position on this issue is wrong for two reasons. First, he improperly includes unplanned tree trimming and mowing in the distribution tree trimming cost per mile, which yields an incorrect result. Second, his recommendation requiring unexpended funds to be recorded as a regulatory liability would be a disincentive to controlling costs.

Q. Why do you think witness Schultz's method of including unplanned tree trimming and mowing with the planned tree trimming when developing a cost per mile is flawed?

A. Unplanned tree trimming is based on customer requests or a particular circumstance identified by a line clearance supervisor that needs attention. These costs are not tracked by mileage, and the amount can vary based on customer requests and the weather. Mowing costs are mostly for transmission rights-of-way, and less than one percent of the mowing is for the distribution system. Mowing is measured in acres; and therefore, a cost per

mile would not be a good measure for either of these items.

A cost per mile for the planned distribution tree trimming is appropriate based on the cyclic nature of this work.

Q. Witness Schultz notes there is a difference between your distribution tree trim cost per mile in your testimony on pages 8 and 9 and the company's response to OPC's Eighth Set of Interrogatories, No. 117. Is there a difference?

A. Yes, there is a difference. The cost per mile stated in my direct testimony included only contractor costs, which is what is filed in the Storm Hardening reports submitted to the Commission annually in March. When including all costs, the distribution tree trim cost per mile in 2008 was $7,351. The forecasted cost per mile for 2014 is $5,245, 29 percent lower than the total cost per mile.

Q. Witness Schultz recommends a test year distribution tree trim amount of $7,319,537 based on the 2012 historical actual cost per mile. Is the cost per mile for 2012 typical?

A. No, the 2012 cost per mile is not typical because 2012 tree trimming activities were not typical. Tampa Electric usually trims the mileage in the service areas on the same cycle as for the overall system. In 2012, there were variations in the cycle time in each of the service areas. The 2012 system actuals represent a 3.67 year trim cycle.

Referring to Document No. 2 of my exhibit, the actual miles trimmed and the mileage of the service areas that were trimmed on the 3.67 year trim cycle are different for each service area. Western service area has a higher than average cost per mile for tree trimming, $7,624 per mile, and Tampa Electric trimmed less than the cyclic miles for that service area. In all of the other service areas, which average a per mile cost of $3,682, Tampa Electric trimmed a greater number of miles. Not trimming the cyclic miles for Western, which has a higher than average cost per mile, and trimming more than the cyclic miles for each of the other areas, with their corresponding lower cost per mile, resulted in an atypical lower cost per mile for 2012. I recommend that the appropriate cost per mile for 2012 would be $4,563 based on contractor costs and $4,859 including all costs.

Q. Why is the tree trimming cost per mile higher in Western service area?

A. Tree trimming cost per mile is higher in the Western service area for two reasons: the density of trees along the distribution lines and the number of distribution lines that were built along the rear of homes, which the company calls "rear lot construction." These conditions require modified trimming techniques to protect the public and the tree trimmers. The tree density consists of more trees along the lines; the trees are larger than the trees in other areas as well. This results in a need for more cutting for proper clearances and a need to trim trees growing over the lines. Trimming trees above power lines requires special techniques to prevent injuries, property damage and outages.

Many lines in the Western service area are rear lot construction and most of these areas are inaccessible by a bucket truck. The cost for trimming trees around these lines is high because each tree must be climbed rather than trimmed from a bucket truck, and this takes considerably more time and results in a much higher cost per mile to trim.

Q. Is the company's proposed level of tree trimming expense for the 2014 projected test year reasonable?

A. Yes. The company's proposed level of tree trimming expense for the 2014 projected test year is reasonable based on the company's expectations about the amount of tree trimming required. Tampa Electric's per mile projected costs are also reasonable. If the $4,859 tree trim per-mile cost that I calculated as typical for 2012 is compared to the projected 2014 cost of $5,245, the resulting per mile increase is less than four percent per year. The company's requested level of tree trimming expense is necessary for Tampa Electric to provide safe and reliable service to its customers.

Q. Witness Schultz recommends that Tampa Electric record a regulatory liability for any unexpended funds and utilize that in subsequent years. Do you agree?

A. No, I do not. A requirement to record unexpended funds as a regulatory liability provides a disincentive to control costs. Tampa Electric has worked hard to reduce costs, and this cost control has helped to keep the company from initiating a base rate case proceeding before now, to the benefit of customers.

VERIZON POLE ATTACHMENT LITIGATION COSTS

Q. Please summarize the key concern you have regarding the substance of witness Ramas's testimony concerning the exclusion of $520,000 in expenses associated with the litigation against Verizon to recover unpaid joint use rental fees. These fees are referred to in Ramas's testimony as "pole attachment charges".

A. My key concern is that witness Ramas's assumptions are based on a lack of understanding of the litigation against Verizon to recover unpaid joint use rental fees.

Q. What is the purpose of the above-referenced litigation against Verizon?

A. Verizon and Tampa Electric have a contract detailing how joint use of their respective utility poles will be handled operationally and financially. Under this contract, Verizon is obligated to make monthly payments to Tampa Electric. In January 2012, Verizon unilaterally began paying a significantly reduced amount for their contractual share of the costs for jointly used poles. In October 2012, Tampa Electric filed a lawsuit against Verizon for breach of contract to recover the unpaid amounts.

Q. What was included in the test year for Tampa Electric's revenue from the Verizon joint use agreement and what would be the impact if Tampa Electric did not continue this litigation?

A. Tampa Electric included $4.8 million in revenue in the test year based on enforcement of the current contract. Verizon is paying close to $1 million. If Tampa Electric's litigation expense to recover this revenue is not allowed for recovery, then the company's projected test year revenue should be decreased by approximately $3.8 million, to the amount that Verizon is actually paying, as the company would have no chance of collecting the additional revenues that should be paid under the contract.

Q. Why did Tampa Electric pursue this litigation?

A. Tampa Electric pursued this litigation because Verizon breached, and continues to breach, its cost-sharing obligations under the joint use agreement between the parties. Under the joint use agreement, neither party makes rental payments to the other so long as each party owns an equal share of the jointly used network of poles. Verizon, though, owns far fewer jointly used poles than

Tampa Electric; therefore, Tampa Electric bears a disproportionate share of the cost of construction and maintenance of the joint use pole network. The rental payments are designed to offset these additional costs incurred by the party owning more jointly used poles than the other party. It would be unfair for Tampa Electric customers to absorb these costs that are supposed to be paid by Verizon under the joint use agreement.

Q. What action do you recommend if the litigation costs, in the amount of $520,000, are removed from the test year expenses?

A. Removing the litigation costs from the test year expenses would signal to the company that it ought to discontinue this litigation. If the litigation is discontinued, it would be fair and appropriate to decrease 2014 "Other Operating Revenues" by the corresponding revenue of $3.8 million that Tampa Electric is seeking to recover through the litigation because Verizon has no intention of paying what it owes under the contract without litigation. This adjustment would increase the company's revenue requirement to be recovered from base rates by $3.8 million, which would in turn increase the total amount of the rate increase requested by the company.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. There are some serious errors in the testimony filed by witnesses Kollen, Schultz, and Ramas. Witness Schultz's assertion that the number of positions in the test year is excessive dismisses the increased workload Tampa Electric will have during the test year. Witness Schultz also has discounted the way that Tampa Electric balances this increased workload between linemen and contractors in order to provide safe, reliable and cost-effective service to customers. I have explained why the company's requested staffing and labor expenses are appropriate and necessary.

Witness Kollen takes a flawed approach to forecast the 2014 Distribution O&M Expense based on 2012 without evaluating all of the Distribution O&M Expense FERC accounts. I have detailed the reasons for increases in the company's test year Distribution O&M Expenses, compared to 2012 expenses.

Witness Schultz's distribution tree trimming cost per mile analysis is flawed by his inclusion of unplanned tree trimming and mowing expense. Neither of these is

appropriate when developing a cost per mile. In addition, the trimming mileage for 2012 was not representative of a typical split between the service areas, and the cost per mile was not typical as a result. Modifying 2012 to reflect a more typical split is appropriate. The company's expected tree trimming miles and costs are a better basis for developing the test year distribution tree trimming expense, as I have described.

And lastly, witness Ramas's testimony concerning the Verizon litigation makes a false assumption at the beginning. She assumes that Tampa Electric is working to increase revenue based on this litigation while not reflecting this potential revenue and only recording the cost of the litigation in the test year. In fact, the litigation is to preserve the joint use fee revenue that is already included in the 2014 test year revenues, which would be greatly reduced if the litigation is discontinued.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT

OF

S. BETH YOUNG

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WITNESS: YOUNG
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Distribution O&M Expense
(000)

2012 Actual	$43,903
2014 Projected	$51,285
Difference	$7,382
Changes from 2012 to 2014:	
3% Inflation	$2,674
IT, Telecom and Facilities Allocations Modified	$1,806
Dispatcher Switching and Training Positions Accounting Changed	$475
Software System Maintenance Fees for OMS and Volt/VAR	$388
Fleet Costs for Meter Department Not Captured in Second Half of 2012	$320
Fleet Allocation Methodology Changed	$420
Incremental Pole Loading Analysis Costs to Comply with Hardening Plan	$100
Meter Reclassification	$587
Headcount - New Positions	$612
Total	$7,382

TAMPA ELECTRIC COMPANY
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EXHIBIT NO. ___ (SBY-2)
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Tampa Electric Company's
2012 Tree Trim Analysis

2012 Actuals					2012 Cyclic		
Service Area	Total Miles Cut	Trim Cycle	YTD	Contractor Cost Per Mile	3.67 System Trim	Costs	Contractor Cost Per Mile
Central	301.68	3.48	$1,576,411	$ 5,225	285.9	$1,493,954	$ 5,225
Dade City	109.56	3.37	$ 242,491	$ 2,213	100.8	$ 223,102	$ 2,213
Eastern	238.91	3.53	$1,262,729	$ 5,285	229.8	$1,214,580	$ 5,285
Plant City	345.25	3.59	$1,445,778	$ 4,188	337.5	$1,413,324	$ 4,188
South Hillsborough	220.77	3.39	$ 679,730	$ 3,079	203.9	$ 627,789	$ 3,079
Western	222.70	5.04	$1,697,864	$ 7,624	305.6	$2,329,893	$ 7,624
Winter Haven	278.53	3.34	$ 585,085	$ 2,101	253.6	$ 532,716	$ 2,101
Adjustment			$ 3,827				
Total	**1717.4**		**$7,493,915**	$ 4,364	1,717.1	**$7,835,358**	$ 4,563
Costs - 6.49%				$ 4,647			$ 4,859

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COMMISSION
CLERK

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT
OF
BRAD J. REGISTER

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

BRAD J. REGISTER

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

A. My name is Brad J. Register. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Compensation and Benefits.

Q. Are you the same Brad J. Register who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors and shortcomings in the prepared direct testimony of witness Schultz, testifying on behalf of the Office of Public Counsel ("OPC") and witness Kollen, testifying on behalf of the WCF Hospital Utility Alliance. I also

address one additional issue on Supplemental Executive Retirement Plans that was not the subject of intervener testimony, but was added to the issues list for this case.

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes. My Exhibit No.__ (BJR-2) contains one document that was prepared by me or under my direction and supervision and is entitled "Details of Headcount Increase by Position."

Q. Please summarize the key concerns and disagreements you have regarding the substance of witness Schultz's testimony.

A. My key concerns and disagreements with the interveners are as follows:

1. The recommended 2014 test year headcount by witness Schultz is not the appropriate level based on the 2014 workload needs of Tampa Electric to appropriately serve its customers. The projected headcount in MFR Schedule C-35 of 2,455 is the appropriate level for the test year based on the

company's workload projections.

2. Witness Schultz's perspective on Tampa Electric's annual incentive program does not appropriately recognize the company's annual compensation benchmark analysis and the importance of the Performance Share Program to maintain total annual compensation near the market median enabling the company to continue to attract and retain high caliber team members.

3. Witness Schultz mischaracterizes the company's stock compensation program, including who participates in the plan, and his testimony does not recognize the appropriateness of this approach to compensation for the company's officers and key employees in order to hold their total remuneration near the market median enabling the company to continue to attract and retain the high caliber team members in this group.

HEADCOUNT

Q. Are there any inconsistencies in the headcounts in the company's filing and its responses to discovery requests?

A. No. Witness Schultz points to inconsistencies that simply do not exist. For example, he inappropriately compares the company's responses to Staff's Sixth Set of Interrogatories No. 95 and Office of Public Counsel's ("OPC") Eleventh Set of Interrogatories No. 141. These two interrogatories ask two different questions from two different time perspectives. Therefore, two different answers were submitted in response to these two interrogatories which should not be a surprise when someone analyzes the details of each question and answer. Staff's Sixth Set of Interrogatories No. 95 requests a comparison based on average headcounts, and OPC Eleventh Set of Interrogatories No. 141 requests a comparison based on specific reference months (December 2012 and December 2014). Headcounts within Tampa Electric and most companies change almost daily due to new hires, terminations, retirements and voluntary resignations. As a result, a meaningful headcount analysis requires more than simply subtracting two numbers to get the resulting difference.

Q. Are there any fundamental differences in the headcount numbers contained within MFR Schedule C-35 for certain years that affect the responses to the interrogatories addressed in witness Schultz's testimony?

A. Yes. On MFR Schedule C-35, the headcount numbers, *i.e.* average number of employees, for the years before and including 2012 are based on the actual number of team member ("employees") at Tampa Electric. The average headcounts for these years do not include budgeted positions that are not yet filled each month ("vacancies"). For the future years of 2013 and 2014, the headcount numbers include currently filled positions at the end of 2012, unfilled positions at the end of 2012 that were budgeted in 2012, and new positions for 2013 and 2014 which are needed based on the workload projections of the various business units. The appropriate number of positions, whether budgeted and managed in dollars as the company did prior to 2013 or budgeted by headcount (and managed in dollars) as the company implemented after its ERP system project in 2012, is determined by each department based on their projected workload and responsibilities.

Q. Do you agree with witness Schultz's assertion that there is an issue with the way the company budgets payroll?

A. No. While I do agree that employee count is an important component of determining an individual department's budgeted payroll needs, I do not agree that

headcount is the most appropriate and correct way to track and monitor actual payroll expenses. At Tampa Electric, all department head leaders are held accountable for the expenditures within their respective areas. From a payroll perspective, the company does not simply count heads to manage the business, but manages the expenses associated with overall workforce labor. This includes managing not only the base salary of team members, but all labor resource expenditures including overtime, temporary employees, contractors, etc.

Q. Do you agree with witness Schultz's position that the addition of an average of 114 employees for the rate case test year compared to 2012 actuals is questionable?

A. No. Witness Schultz makes a number of assertions and conclusions all intended to support his position related to Tampa Electric's requested headcount additions. However, none of his issues really address the most important question, namely whether Tampa Electric's headcount for 2014 is a reasonable and prudent level based on the workload in the test year? Below I address a number of items spread throughout his testimony that are incorrect or misrepresentations of the facts.

Witness Schultz suggests that the 2,548 headcount approved by this Commission for the 2009 test year during the company's last base rate proceeding (Docket No. 080317-EI) never materialized. In fact, considering the first six months of 2009, the average headcount at Tampa Electric was 2,533, almost equal to the approved test year headcount. As discussed in my direct testimony, the company undertook a reorganization in mid to late 2009 which affected the overall headcount at Tampa Electric. This reorganization was a business management decision necessary to maintain a reasonable and prudent cost profile given the changing electric revenue profile taking place at that time. As a result, a substantial number of team members left the company in late 2009 resulting in an actual headcount for the full year below the Commission approved level. The downsizing which occurred during the 2009 reorganization was a difficult response to a serious revenue situation; it caused individual team members to significantly increase their workload and responsibilities, which is potentially sustainable in the short-term but not in the long-term. Witness Schultz's reliance on the full year average for 2009 is misleading, especially since the company's actual headcount for the first six months, before the reorganization, was within one percent of the

number approved by the Commission.

Witness Schultz points to the March 31, 2013 actual headcount being below the projected headcount budget for March 2013 as another reason to question the test year request. In fact, the actual headcount in a particular month will almost always be below the budgeted headcount for that month because actual headcount numbers do not include vacant positions while budgeted headcounts do. Budgeted payroll is based on the team member resources needed to complete all work as projected by the individual department heads. Currently, at any given time, an average of about 30 positions will be vacant at Tampa Electric as the company's Recruitment and Staffing group works to fill these positions. In essence, there will always be transitional vacancies since new vacancies constantly result from team members leaving the company, as well as from team members filling internal vacancies, which in turn causes a vacancy in their former position. Even though some positions are vacant, all the work must still be completed to safely and reliably serve all of our customers. This means that the dollars budgeted during the period when a position is vacant will be used to ensure that the work associated with that position is completed. This is

accomplished via a number of methods to complete the required work including the use of temporary employees, contractors, increased overtime of existing team members, and spot bonuses for exempt team members being asked to carry a substantially greater workload resulting in substantially increased work hours. Just recently, Tampa Electric transferred one of its existing Human Resources team members into the Recruitment and Staffing area to work on reducing the average number of vacancies and the average time to fill a job. This addition increases the number of recruiters by 33 percent and should have a positive future impact on reducing transitional vacancies.

Witness Schultz suggests the company has not provided sufficient support for the additional positions requested. As detailed in response to Staff's Sixth Set of Interrogatories No. 95 and Document No. 1 of my exhibit, a total of 82 new positions are being added in 2013 and 2014. Of these positions, 94 percent are in the front line areas of Customer Service, Energy Delivery, and Energy Supply. The need for these positions is discussed in detail by Tampa Electric witnesses Karen J. Lewis, S. Beth Young, and Mark J. Hornick.

Witness Schultz also states that "Tampa Electric has a history of requesting significant amounts of additional positions that never are filled, yet ratepayers are supporting these unfilled positions" but offers no testimony in support. His statement is simply not correct. It is a misplaced view of the broader concept of vacancies somehow suggesting that we are always talking about the same positions always being vacant. That couldn't be further from the truth. Positions become vacant and are filled, thus eliminating that vacancy. At the same time, other positions become vacant due to team members leaving the company or transferring to a different job creating a new, but distinctly different vacancy. In addition, witness Schultz completely missed the important concept that even though a position is vacant, the work associated with that position still has to be accomplished requiring resource dollars which are available from the original budget associated with the position.

An analysis of the positions that contribute to the 114 average headcount increase between the 2014 budget average and the 2012 actuals average shows that they are roughly split into three equal parts. About 1/3 of the positions are vacancies that were unfilled at the end of

2012, about 1/3 are new positions for 2013, and about 1/3 are new positions for 2014. Of the 2012 hold over vacancies and the 2013 new positions, 85 percent have already been filled, 4 percent are in the process of being filled, and 11 percent will be filled during the remainder of 2013. This demonstrates Tampa Electric's vigilance in filling the positions which are budgeted based on the business units' workload requirements.

Q. What specific new positions has Tampa Electric proposed to add during 2013 and 2014 and what is the justification for these new positions?

A. In response to Staff's Sixth Set of Interrogatories No. 95 and Document No. 1 of my exhibit, Tampa Electric details the 82 new positions which it plans to add in 2013 and 2014. While additional details and justifications on most of the new positions are provided in the testimony of witnesses Lewis, Hornick and Young, I would like to provide a few summary comments. It is important to note that these new positions have a much lower average gross salary ($58,720) than the company's overall employee population average ($87,226) and that no officer, director, or managerial additions are included in this group with the exception of one

supervisor over the new Water Plant Operations group. Quite a few of these new positions are administrative or frontline starting positions with over half of the proposed new positions being Customer Service Professional's ($34,000 base salary) or Apprentice Linemen / Apprentice Substation Electricians ($45,000 base salary).

Ten new positions are in Customer Service. Eight of these positions are directly supporting customers as Customer Service Professionals or Billing Specialists and two are new staff support positions in areas currently without adequate administrative support. These additions will improve service to our customers and should improve overall Call Center metrics.

Forty-six new positions are in Energy Delivery. Thirty-two are Apprentice Linemen, eight are Apprentice Substation Electricians, and two are Cable Splicers. These are all front line craft positions supporting the operation of Tampa Electric's Energy Delivery system. These positions are needed to support increased capital including the Polk 2-5 Combined Cycle Conversion Project, to maintain the company's aging infrastructure, and to prepare for future linemen and substation

electrician retirements. The remaining four positions are needed due to increased workload in the areas of Energy Delivery training (DDT Training Administrator), relay testing requirements (Relay Specialist), and Volt/Var Smart Grid new technology (Associate ESE and Systems Engineer).

Twenty-one new positions are in Energy Supply. Thirteen are needed for Water Plant Operations at the new waste water treatment facility to support the current and future operation of the Polk Power Station site. Seven are new internal positions directly supporting the Polk 2-5 Combined Cycle Conversion Project. One final engineer position is in the Energy Supply Planning, Strategy and Compliance group, due to new workload associated with expanded NERC/CIP reliability standards compliance.

The remaining five new positions are: Power Originator - needed due to increased workload related to wholesale power market activity; Smart Grid Administrator - needed by the Information Technology department to support the Energy Delivery Smart Grid implementation; Senor Account Manager - needed to provide increased support to Commercial and Industrial customers; Telecom Apprentice

Electricians (2) - needed to support system expansion and supplement the existing workforce to prepare for future retirements of Telecom Electricians beyond the four year apprentice training period.

Overall, these incremental positions are needed due to capital expansion including the Polk Project, increased workload associated with the company's aging infrastructure, to prepare for future retirements, to maintain system reliability, to improve direct customer service including Call Center metrics, to address compliance requirements, and to address workload additions due to new technologies like Smart Grid.

Q. In addition to the detailed headcount justifications provided by company witnesses, is there an overall headcount measure which shows that the company's proposed headcount is reasonable?

A. Yes. The ratio of customers served per team member shows that the company's proposed level of staffing as reflected in its headcount is reasonable. For 2009, the company's previous test year, the Commission approved a headcount of 2,548 when the company's average customer count was 666,750. This results in a customer to team

member ratio of 262. For 2014, the test year in this case, the requested headcount is 2,455 with a projected customer count of 701,415. This results in a customer to team member ratio of 286. Given the improvement in this ratio and the more significant detailed headcount related testimony provided by Tampa Electric's witnesses, the Commission should approve the 2014 test year headcount request of 2,455 to be reasonable and prudent.

Q. Does the history discussion in witness Schultz's testimony justify his recommendation of 2,351 positions in the test year?

A. No, for several reasons. First, witness Schultz suggests that looking back at actual headcount increases during the entire period before the company's last rate case (1992 to 2007) is appropriate and somehow supports his position on Tampa Electric's 2014 test year headcount. This approach is arbitrary and unreasonable because it is unaccompanied by any proof that operating conditions for the company from 1992 to 2007 are similar to current and future expected operating conditions, which they are not.

If looking back at headcount during the period of 1992 to 2007 were an appropriate measure, one might suggest that the average headcount in this entire period (1992 to 2007) somehow demonstrates the appropriate headcount in the 2014 test year. That would result in a request for 2,778 positions based on the 1992 to 2007 average, substantially above Tampa Electric's actual request of 2,455 for 2014. This flawed logic is simply not an appropriate comparison in either case. Headcount for the test year should be based on a prudent and reasonable current year headcount including vacancies and new additions to address increased workload as anticipated in the test year due to new technologies, capital expansion, increased customers, increased maintenance, improved reliability, improved customer service, etc.

Second, witness Schultz seems to suggest that Tampa Electric's decline in the average number of positions in 2009, 2010, and 2011 somehow supports his position that no headcount increase is needed between 2012 and the 2014 test year. As previously discussed, the headcount numbers during the 2009 through 2011 period were driven by the company's reorganization in 2009 and a conscious decision to refrain from adding new positions and from

filling some vacant positions in order to address revenue shortfalls. This was a very difficult position for management to take given the stress it placed on team members to deliver on all of their increased job responsibilities while continuing to contribute to the delivery of reliable service to our customers as the company' system continued to expand and the total number of customers continued to increase. To suggest that this hard work somehow demonstrates and justifies no need for future headcount increases is flawed logic. If you remove this extraordinary period of 2009 to 2011 and focus on the remaining most recent years (2006, 2007, 2008, and 2012), Tampa Electric's required headcount grew an average of 50 positions per year on an actual basis. The growth rate during these more normal business times closely aligns with the average headcount increase of 114 requested for the two-year period between 2012 and the 2014 test year. Again, it is important to remember that the new positions added over this two-year period total only 82 (41 per year average) with the remaining resulting from filling vacant positions budgeted in 2012 to eliminate the replacement resource expenditures discussed previously.

Finally, witness Schultz tries to suggest that the

headcount of 2,548 approved for 2009 by the Commission is somehow flawed causing an improper over-recovery of payroll expense from 2009 to 2012. He further seems to suggest that somehow the previously approved level of headcount somehow helps to justify his position that headcount from 2012 to 2014 should only be increased by 10.

This logic is flawed. While Tampa Electric's total payroll expense not including the expenses associated with the corporate restructuring in 2009, in the period 2009 to 2012 was below the Commission approved level set in 2009, any over-recovery argument only considers this topic in a vacuum. During this same period, Tampa Electric's benefit expense was higher than the 2009 Commission approved level resulting in an under-recovery in this area. Both of these arguments individually are still looking at the issue of appropriate cost recovery in a vacuum. The meaningful point is that at no time during this period was Tampa Electric earning above its allowed rate of return. In other words, Tampa Electric was managing its total budget and resources in a manner consistent with overall Commission approved levels at a time when Commission approved expected revenue never materialized. Overall, during this time period, Tampa

Electric undertook the appropriate actions to control its cost profile in order to avoid another rate case during this period.

Q. What is the significance of the apprenticeship program discussed in witness Schultz's testimony?

A. Witness Young has discussed these programs in great detail in her testimony, but I would like to offer one additional thought on the program's importance to Tampa Electric's overall aging workforce strategy. The lineman and substation electrician apprenticeship programs and their new entrants are very important to the successful operation of the company's energy delivery system. In addition to providing additional needed lower cost manpower for upcoming capital projects and supporting increased maintenance needs, these programs are also feeder programs with a four year training cycle which are used to populate a number of critical jobs including linemen, substation electricians, troublemen, system dispatchers, and operations supervisors. The people who serve in these positions are directly involved in ensuring the company's electric system will reliably and safely deliver power to our customers. It is critically

important that Tampa Electric continue to add to these ranks to mitigate the effects of the aging work force given the potential retirements of the experienced and knowledgeable team members in these areas within the next five years. Absent a workable apprenticeship program for these key positions, the company will likely find itself in a position in the future where it cannot fill positions that are vital to good customer service. In this regard, witness Schultz's criticism of the company's "continuation" of an apprentice hiring and training program is misguided, short sighted and fails to consider the realities we are facing in the labor market.

Q. Do you agree with the adjustment witness Schultz recommends to the employee complement and the associated calculation methodology included in witness Schultz's Exhibit ___ (HWS-2), Schedule C-1?

A. No. Witness Schultz has provided no testimony to demonstrate the reasonableness of his projected headcount in 2014 which would eliminate 104 positions from Tampa Electric's proposed 114 average headcount increase which results from the addition of 82 new positions in 2013 and 2014 and the filling of the vacant

budgeted positions which existed at the end of 2012. Further, any use of his disallowance calculation is flawed as it uses the overall gross average salary of all positions included in the 2014 test year as its starting point. A proper calculation should use the gross compensation for the actual positions that are proposed to be eliminated. Given that we really don't know exactly which positions witness Schultz is proposing to eliminate, there is no possible way to make this calculation. However, to demonstrate how far off witness Schultz's methodology really is, I would offer the following. The gross average salary in the test year as shown on MFR C-35 is $87,226. This includes both base salary (fixed) and PSP (variable pay). For the 82 new positions proposed to be added in 2013 and 2104, the average gross compensation is just over $59,000. Therefore, the method used by witness Schultz in Schedule C-1 is over-stated by approximately 32 percent.

PERFORMANCE SHARING PROGRAM

Q. Does witness Schultz correctly characterize Tampa Electric's Performance Sharing Program?

A. No. Throughout witness Schultz's testimony, there are

numerous mischaracterizations and misstatements about the appropriateness of Tampa Electric's Performance Sharing Program ("PSP") and its design as presented in my direct testimony. Most of the arguments center on the design of the PSP program. I believe that the details of the PSP design should be left up to the company's management. They are the ones responsible for maintaining the financial integrity of the company and for providing safe and reliable electric service over the long-term and they are in the best position to determine the most efficient way to run the company from year to year as conditions change. From a regulatory perspective, the inquiry should be whether the total expense of Tampa Electric's overall compensation program is reasonable and prudent and whether the level of PSP included in this analysis contributes to an appropriate total annual compensation level.

Q. Why is PSP an important part of Tampa Electric's overall compensation program?

A. All positions are initially evaluated relative to the market median for that position to determine the appropriate average total annual compensation level. The company then performs benchmark studies for a core

group of jobs to ensure that the company's compensation keeps pace with the market median level. As demonstrated in my direct testimony, Tampa Electric was just below the market median for total annual compensation as tested in the 2012 benchmark analysis. This compensation analysis includes both a fixed component and a variable component. Tampa Electric's annual merit pay process is designed to provide team members an opportunity to earn an increase in base salary (fixed compensation component) each year in order to reward individual performance and to stay competitive with appropriate market fixed compensation levels. Tampa Electric's PSP program is the variable component of pay intended to maintain total annual compensation levels at the market median.

Q. Is the annual incentive pay really "at risk"?

A. Yes. Witness Schultz incorrectly raises the idea that the PSP incentive is not "at risk" by stating that almost every employee gets the payout each year. This totally misses the point of this program. For over 93 percent of the company's team members, not including officers and key employees, PSP is "at risk" as to the amount paid each year not to the percentage of

individuals who receive PSP as all team members in good standing receive the same payout percentage. PSP is an overall team incentive program. Witness Schultz also suggests that PSP is a *de facto* annual bonus. Again, the target level for PSP is included in all of the company's compensation benchmark studies. Therefore, on average, Tampa Electric expects to pay the target level to maintain its total annual compensation position relative to the market median. As discussed in my direct testimony, PSP has paid out 4.54 percent on average for the period 2008 through 2012 for the non-officer/non-key group, which is keeping the company tracking just below the market median during this period.

Q. If variable pay is part of total annual compensation, why not just increase base pay and eliminate this program?

A. That is certainly an option, but not one favored by Tampa Electric. However, most companies in the electric utility industry including Tampa Electric utilize a variable pay component which is at risk each year to drive and motivate team members to achieve high performance levels through the attainment of various

goals usually centered around areas including safety, cost control, resource optimization, reliability, customer centric solutions, etc. Further, a variable pay component allows management the opportunity to react to revenue and expense conditions each year as part of good management of the company.

Q. Is witness Schultz correct in his assessment that the company has requested five percent for incentive payments in addition to an across-the-board three percent base pay increase?

A. No. This characterization fails to recognize that the five percent annual incentive target is part of the company's total annual incentive compensation that is benchmarked to the market median and is currently below this level. Also, the comment of an "across-the-board" increase implies that all team members receive this same increase no matter their performance. While this concept is true for the company's union covered team members due to their collective bargaining agreement, it is not true for all exempt and NC/NE team members. The merit program is based on performance of the individual, not an across-the-board increase.

Q. Does witness Schultz correctly explain target and goal levels for incentive compensation plans correctly?

A. No, he does not. For 93 percent of Tampa Electric's team members, those who are not officers or key employees, there are no minimum, threshold, or maximum levels within the program. Each goal has an absolute level for achievement. For example, if the absolute safety goal is not met, this goal will pay out zero. If the goal is met or exceeded, it will pay out a two percent, not a higher amount as suggested by witness Schultz.

Q. Are the various concerns with the company's incentive plan objectives raised by witness Schultz valid?

A. No. Witness Schultz suggests that the operational goals have been tied to the financial goals which benefit the shareholders, not the rate payers. This logic is flawed. For the past several years, as Tampa Electric worked hard to control its costs given almost no revenue growth, a difficult management decision was made to add a self-funding mechanism to the three percent operational goals beginning in 2010. These operational goals were still earned based on operational parameters,

which benefit ratepayers, but would only be paid if net income above budgeted net income levels was available to fund the payout. To suggest that this somehow makes the operational goals *de facto* financial goals, which only benefit the shareholders is simply incorrect.

The company's 2010 decision to add a self-funding mechanism to the operational goals was very difficult and has placed Tampa Electric in a position where the average payout for PSP is reduced, driving the company's total annual compensation further below the market median. Given a two percent average payout for most team members over the past few years, far below the five percent target included in the company's compensation benchmark analysis, it was necessary for the company to remove this self-funding mechanism in 2014 in order to maintain its relative benchmark position. The difficult action taken by management in the PSP program has affected team member morale and is not sustainable. Being below the market median for total annual compensation will damage the company's ability to attract and retain a highly skilled workforce especially as the economy continues to improve and offer choices which have not been available during the past two years. For this reason, the company needs to

eliminate the self-funding mechanism associated with the operational goals.

It has also been suggested that incentive goals should not include financial goals, including parent company financial goals, since there is no benefit to the ratepayer and only the shareholder sees a benefit. This misses the point that financial goals, including parent financial goals, which are directly tied to the company's performance, also benefit customers by encouraging team members to find ways to keep costs down and find more efficient ways of doing things that ultimately result in lower cost profiles for future rate cases.

Q. How will the company's overall compensation relative to the market be affected by the Commission not granting the PSP amount included in Tampa Electric's rate request?

A. The real issue here is the reasonableness of Tampa Electric's overall compensation program. As demonstrated in my direct testimony Document No. 2 of my Exhibit No. __ (BJR-1), Tampa Electric's total annual compensation analysis for 2012 shows the company to be

five percent below the market median. This analysis looks at total annual compensation and includes both base salary and PSP at the target level. For non-key employees and non-officers, representing 93 percent of the company's overall team member population, this target level is five percent. For key employees and officers, the PSP is set at the appropriate target level for each position. If PSP is reduced to two percent for all employees as suggested by witness Schultz, Tampa Electric's total annual compensation as referenced above will drop to 12 percent below the market median which is unacceptable from a team member attraction and retention perspective.

Q. Why is $12.383 million the correct and appropriate level of variable pay in Tampa Electric's PSP program for 2014, if the 2013 budget is only $7.168 million?

A. The 2014 budget of $12.383 million was determined by using the 2013 budget as a starting point, adjusting for a three percent average salary increase across the employee population, and then adding $5.0 million to fund the three percent of operational goals to allow the removal of the self-funding mechanism for the non-officer and non-key employees. Witness Schultz suggests

that "it is inappropriate to ask ratepayers to cover such expenses (PSP) during a rate case, when the company is unwilling to make the same payment outside a rate case". This perspective is not correct. The proper perspective is whether are not the PSP amount in conjunction with base pay in the test year is appropriate and consistent with the market median which establishes the norms for compensation. It is imperative that Tampa Electric's PSP target for 93 percent of the company's team members be returned to the five percent level without a self-funding mechanism to help ensure this target level is more attainable in a normal financial year to be consistent with the variable pay level used in the company's benchmark market median analysis.

Q. Witness Schultz offers two alternative calculations for incentive pay in the test year. Are there problems with his primary recommendation and associated calculations as presented in HWS-2 Schedule C-2?

A. Yes. I do not agree with witness Schultz's primary or secondary recommendations since they do not support the appropriate PSP level for 2014 to maintain the company's jobs at the market median for total annual compensation.

In addition to that concern, there is a significant flaw in his primary calculation and methodology.

Q. What is the flaw in his calculation?

A. In his primary adjustment calculation, an overall two percent PSP allowance is used for all employees resulting in an expense of $2.5 million. From witness Schultz's testimony this is based on the two percent safety PSP paid in 2012. However, he fails to recognize the appropriate level of PSP for officers and key employees as paid in 2012 since he is using that year to establish his baseline. As presented by the company in response to OPC's Eleventh Set of Interrogatories No. 147, the total PSP expense (O&M) for 2012 was $4.5 million with a total PSP amount of approximately $7 million.

Q. Are there any other problems with witness Schulz's alternative methodology?

A. Yes. In his alternative methodology witness Schultz suggests that the ratepayers and the shareholders should share the cost of the PSP program. His position fails to recognize how the PSP program works and how it is

integral to Tampa Electric's total annual compensation program. At the program's target payout levels, it is intended to maintain the company's total annual compensation at a level consistent with the market median. Therefore, as an appropriate and reasonable expense associated with the normal course of business, the target payout amounts for PSP should be recovered though rates. PSP payouts above the target level are not included in this rate request. Therefore, any payout expense above target levels will appropriately be borne by the shareholders.

Q. Is witness Schultz's position to disallow TECO Energy incentive compensation allocated to Tampa Electric correct?

A. No. In its Final Order (PSC-09-0283-FOF-EI) issued on April 30, 2009 in Docket No. 080317-EI, the Commission did not make any adjustment to the TECO Energy incentive program allocation to Tampa Electric. This was the proper treatment as these allocations are related to TECO Energy team members and the correct question should be whether or not their total annual compensation is consistent with the market median and therefore reasonable and prudent. Since on average TECO Energy

pay is just below the market median, all of the incentive in question should be allowed to flow through the company allocation mechanism.

ADDITIONAL BENEFIT ADJUSTMENTS INCLUDING STOCK COMPENSATION

Q. Do you agree with the benefit reduction calculation included in witness Schultz's Exhibit ___ (HWS-2), Schedule C-3?

A. No. As stated previously, no adjustment to the projected team member headcount for 2014 should be made. However, if the Commission does decide to make an adjustment to headcount, the calculation contained in the referenced schedule is flawed. It assumes that all benefits should be allocated evenly across all positions. This is not true for pension plan, post-retirement medical, and stock compensation expenses as the amounts contained in MFR Schedule C-35 do not include any additional costs associated with the new positions to be added in 2013 and 2014. Therefore, these expenses should be subtracted out from witness Schultz's calculation to determine the average expensed cost per employee. Since retiree medical and pension plan total cost in 2014 of $23,908,000 represents 40 percent of the Net Employee Benefit cost in witness

Schultz's Schedule C-3 line 4, his overall calculation methodology yields a result that is over-stated by 40 percent.

Q. Is witness Schultz's characterization of the company's stock compensation plan correct?

A. No. Witness Schultz states that this is an executive-type plan limited to five highly compensated executives and is discriminatory since it only applies to these select executives. While the company's stock compensation plan does include all of the Tampa Electric and TECO Energy officers, it also includes key employees. In fact, the program is not limited to five individuals; there are just over 200 employees participating in this program at Tampa Electric and TECO Energy.

As to the reference to highly compensated executives, the real point is whether or not an officer's overall compensation is appropriately market based. As provided in Tampa Electric's confidential discovery, the company's external consultant to the Board Compensation Committee benchmarks each officer's total remuneration on an annual basis to position these employees at the

market median on average based on their position and responsibilities. Total remuneration includes base salary, annual incentive, and stock compensation. Based on the company's last Steven Hall & Partners market study, the group of Tampa Electric and TECO Energy officers was just below the market median in base salary, total cash compensation (base salary plus annual incentive) and total remuneration. For key employees, Steven Hall & Partners performs an analysis of long-term stock compensation based on key employee grade levels and average salaries to target marketplace median. The long-term stock compensation for each grade level is then set exactly at the market median. Based on the analysis performed by Steve Hall & Partners as outlined above, the Commission should allow all of the stock compensation expense for Tampa Electric and TECO Energy as outlined in the company's rate case filing in this case as a reasonable and appropriate expense based on current market benchmarks.

Q. Does your rebuttal testimony above adequately address other intervener testimony in these same areas?

A. Yes, it does. In addition to the specific intervener testimony that I address above, witness Kollen raises

some of the same general issues in the areas of PSP and stock compensation and there is no need for me to repeat my testimony.

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

Q. Does the company have a Supplemental Executive Retirement Plan?

A. Yes. The company maintains a Supplemental Executive Retirement Plan ("SERP"), which includes twenty-four current and former executives at Tampa Electric and TECO Energy. The company's SERP is a non-qualified retirement plan providing benefits to some executives beyond those provided in the qualified retirement plan and represents a portion of the participating executive's overall compensation and benefits package.

Similar to the company's Performance Sharing Program and stock based compensation program (i.e., Long-Term Incentive Plan), SERPs are provided to some executives based on market studies for the purpose of ensuring that the company's participating executives are compensated at a market level and in a manner similar to the way other similar executives in the market are being compensated. Fundamentally, a SERP is provided as an

attraction and retention tool to ensure a high caliber workforce at the executive level. Not all current or former executives participate in the SERP, since an officer's position is analyzed using market data to determine if a SERP is warranted for an individual position and level. SERPs at the executive level have been a prevalent compensation program tool for companies throughout the United States over the past twenty or more years, but their use for new executives has significantly decreased in recent years. In the past nine years, there have been no new SERP participants added at Tampa Electric and only one new SERP participant has been added at TECO Energy, which took place in 2009.

Q. Should an adjustment be made to pension expense associated with the SERP for the 2014 projected test year?

A. No. As a preliminary matter, no party has proposed any such adjustment or presented any testimony or exhibits supporting any such adjustment.

The jurisdictional amount of pension expense associated with the SERP for the 2014 projected test year including

both current and former Tampa Electric executive participants is $793,000. This amount is included in the Pension Plan line item on MFR C-35. Given that some current and former TECO Energy executives also participate in the SERP, an additional SERP expense of $1.6 million is allocated to Tampa Electric by TECO Energy. These amounts are based on actuarial analysis of the SERP shown in various Mercer reports provided on a confidential basis in the company's discovery.

A SERP is one component of an overall compensation and benefits package designed to help recruit and retain talented, highly motivated and effective executive leadership. As I stated earlier, the real point is whether or not an officer or key employee's compensation is appropriately market-based. In this regard, the company has always and will continue to ensure through studies provided by the Board's Compensation Committee consult that a SERP is appropriate to maintain a particular executive at the market median for their position and level. No adjustment should be made for SERP benefit expenses for these reasons, which are consistent with my direct testimony on why it is inappropriate to reduce test year O&M expenses for the company's PSP and stock based compensation program.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. A number of issues were raised through intervener testimony in the areas of headcount, PSP, and stock compensation. The interveners suggest that specific adjustments should be made to Tampa Electric's rate case request in these areas. However, the expenses associated with headcount, PSP, and stock compensation are reasonable and prudent and should be allowed by the Commission at the levels contained in Tampa Electric's rate request.

In fact, in the area of headcount, witness Schultz proposes that the 2014 test year headcount should be reduced by 104. However, he provides no testimony as to the specific positions that should be eliminated. Does he propose eliminating the Customer Service Professionals needed to improve the frontline Contact Center interface with our customers? Does he propose eliminating the Water Plant Operators needed to reliably and safely operate the new waste water treatment facility, which will support the current and future operation of the Polk Power Station site? Does he propose to eliminate the Apprentice Linemen, Apprentice

Substation Electricians, or Cable Splicers who are needed to complete planned capital projects necessary to reliably serve our customers, to complete maintenance work in support of the company's aging infrastructure, and to prepare for future retirements? Does he propose to eliminate the engineers and support personnel needed to complete the Polk Power Plant expansion? I could go on but in fact, witness Schultz has not proposed one specific position elimination based on the positions being added in 2013 and 2014.

Finally, no intervener presented any evidence or analysis to demonstrate the reasonableness of Tampa Electric's total compensation program. Given that Tampa Electric did present such evidence demonstrating its overall compensation program to be reasonable and prudent, the company should be allowed to retain all compensation related expenses, including stock compensation as proposed in the this rate proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
WITNESS: REGISTER

EXHIBIT

OF

BRAD J. REGISTER

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Details of Headcount Increase by Position

Functional Area	Department	# of Positions	Position Title	Individual Salary	Avg Salary for all new Positions
Customer Service	CUSTOMER SVC ADMIN	1	SR Admin Spec. (Quality Assurance)	39,732	39,732
Customer Service	PAYMENTS - CHANNELSIDE	1	Admin Spec.	40,000	40,000
Customer Service	PAYMENTS - CHANNELSIDE	2	Billing Specialist (Payments)	40,127	80,254
Customer Service	CALL CENTER	6	Customer Service Professional	33,913	203,478
Energy Delivery	ENVIRONMENTAL	1	DDT Training Administrator	91,087	91,087
Energy Delivery	METER OPERATIONS - COC	1	Relay Specialist	55,043	55,043
Energy Delivery	RF & CONTROL SYSTEMS - ECC	1	Associate ESE	70,699	70,699
Energy Delivery	RF & CONTROL SYSTEMS - ECC	1	Systems Engineer	91,087	91,087
Energy Delivery	CENTRAL SERVICE AREA - COC	2	Cable Splicer	74,695	149,390
Energy Delivery	SUBSTATION OPERATIONS - COC	8	Apprentice Substation Electrician	45,802	366,416
Energy Delivery	DISTRIBUTION ADMIN - PALM RIVER	16	Apprentice Lineman I (all year)	44,476	711,616
Energy Delivery	DISTRIBUTION ADMIN - PALM RIVER	16	Apprentice Lineman I (8-May & 8-Sept)	44,476	711,616
Energy Supply	PE&C ADMIN SERVICES, SAFETY, & TRAINING	1	SR Admin Specialist (Polk 2CC Proj)	50,327	50,327
Energy Supply	PE&C ENGINEERING	1	Engineer II (Polk 2CC Proj)	88,179	88,179
Energy Supply	PE&C ADMIN SERVICES, SAFETY, & TRAINING	1	Polk 2CC Proj Support	76,146	76,146
Energy Supply	PLANNING STRATEGY & COMPL - PLAZA 5	1	Consulting Engineer	93,820	93,820
Energy Supply	POLK POWER PLANT	4	Engineer II (Polk 2CC Proj)	88,179	352,716
Energy Supply	POLK POWER PLANT	13	Water Plant Operations	67,979	883,727
Fuels	WHOLESALE MARKETING & SALES - P7	1	Power Originator, Marketing	125,000	125,000
IT	INFORMATION SECURITY	1	Smart Grid Administrator	113,300	113,300
Marketing	INDUSTRIAL ACCOUNT MANAGERS - P5	1	Sr Account Manager	91,866	91,866
Telecommunications	BROADBAND - PALM RIVER	1	Telecom Electrician Apprentice	50,140	50,140
Telecommunications	PBX - PALM RIVER	1	Telecom Electrician Apprentice	50,140	50,140
		82			4,585,779
					55,924
					58,720 w/ PSP

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION FOR AN INCREASE IN BASE RATES

AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY

OF

STEVEN P. HARRIS

ON BEHALF OF TAMPA ELECTRIC COMPANY

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

STEVEN P. HARRIS

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Steven P. Harris. My business address is ABSG Consulting, Inc. ("ABS Consulting"), 475 14th Street, Oakland, California 94612. I am a Vice President with ABS Consulting, an affiliated company of EQECAT, Inc. both of which are subsidiaries of the ABS Group of Companies, Inc.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors in the prepared direct testimony of witness Helmuth W.

Schultz III, who is testifying on behalf of the Office of Public Counsel, ("OPC") and witness Jeffry Pollock, who is testifying on behalf of The Florida Industrial Power Users Group ("FIPUG").

Q. Please summarize the key concerns and disagreements you have regarding the substance of witnesses Shultz's and Pollock's testimonies.

A. My key concerns and disagreements are as follows:

1. I disagree with the Historical loss average approach proposed by witness Shultz and witness Pollock.
2. I disagree that the hurricanes of 2004 should be excluded from my evaluation of storm damage costs.
3. I disagree with witness Shultz that my Study does not comply with Florida Public Service Commission ("Commission" or "FPSC") rules on storm cost recovery.

Q. Is the Historical loss average approach used by witnesses Schultz and Pollock a more accurate approach to predicting future storm loss cost than catastrophe simulation modeling approach?

A. No. Calculating an actual or simulated expected annual

storm damage amount that selectively excludes any possible damage events, whether large and infrequent or small and frequent, is not meaningful. This methodology cannot, and does not, provide probabilities of damage. Any reliable estimate of the expected annual damage (EAD) must include the most complete and full damage distribution, including the frequency of occurrence of storm that can be determined both from actual hurricane experience and from simulated possible hurricane damage.

Hurricane simulation modeling is the standard methodology used in the insurance industry to estimate storm damage. The Florida Commission on Hurricane Loss Projection Methodology, an independent panel of experts to evaluate computer models and actuarial methodologies for projecting hurricane losses, goes to great lengths to ensure that all models used in the State for insurance rating purposes appropriately capture the full range of the hurricane hazard.

Q. Do you agree that a more reliable estimate of annual storm loss would be based on actual 2000 to 2012 data, excluding the year 2004 as extraordinary?

A. No. Not all years will experience damage equal to or

greater than any estimate of the expected annual damage. Many years may experience no loss and others larger losses. Therefore, in developing expected annual damage estimates, the most reliable methodology is to utilize the longest, most complete historical record available. Since Florida's hurricane history is just over 110 years, insurers rely on simulation modeling to extend this "known" history into thousands of simulated years for the purpose of estimating likely damage. The period for 2000 to 2012 is too short to determine a reliable estimate of annual storm damage. The simulated expected annual damage to Tampa Electric's system is the best estimate of the annual damage considering all possible future hurricanes.

The reason that Tampa Electric's annual accrual appears to have been sufficient between 2000 and 2003 (excluding the real losses from the hurricanes of 2004) is Tampa Electric's favorable storm history. There have been no hurricanes with direct landfalls in Tampa Electric's service territory from 2000 up until the present. The hurricanes of 2004 made landfall outside of the Tampa Electric's service territory and the wind speeds within the service territory were only at tropical storm levels. Considering that the 2004 storms had sub-tropical winds

in the Tampa area, their effects are certainly ordinary for Florida, even though the losses for Tampa Electric were large.

Tampa Electric's management and the Commission would be ill-advised to rely on Tampa Electric's recent good luck over a selective and short number of years considered by witness Schultz and Pollock. Over Florida's 110-year hurricane history, there have been many more hurricane landfalls and damaging events than in the last 12 years. The EQECAT Storm Loss Analysis model considers the broader and longer storm history.

Q. Do you agree with witness Schultz that the study does not comply with the Commission's rule on storm cost recovery?

A. No. The Storm Study is composed of two separate but related analyses. The Storm Loss Analysis provides a hurricane loss simulation considering all of the historical data on hurricane landfalls, estimates the expected annual damage to restore service in Tampa Electric territory, and provides the loss non-exceedance probabilities, measures of the likelihood of damage exceeding a given amount. The expected annual damage from this analysis is estimated to be $21.9 million.

The second part of the Study is the Reserve Performance Analysis. The Reserve Performance Analysis is a cash balance simulation analysis over a prospective five year period starting with an initial reserve balance of $53 million in this case. An annual accrual of $8 million is added to the cash balance. Annual storm losses are simulated and deducted, consistent with the Storm Loss Analysis, for each of the five years. The storm losses are randomly simulated, but over a long period of time they have an average of $17.6 million in damage to Tampa Electric's system for each of the five years in the reserve performance simulations. The $17.6 million is an estimate of the portion of the full $21.9 million expected annual damage determined in the Storm Loss Analysis.

The Reserve Performance Analysis provides a tool that Tampa Electric's management and policymakers can use to determine the performance of the reserve and to test appropriate annual accrual amounts to meet their objectives. One criterion to consider is the target reserve balance to achieve and maintain. This provides a metric to evaluate against possible storm loss events. Another criterion is rate stability. As a policy objective, the questions to ask are: what reserve

balance should Tampa Electric seek to achieve, how quickly should it be reached to provide funds for storm damage events, and what is the likelihood that the reserve will have inadequate funds over the prospective five year period that requires cost recovery and results in rate volatility? Once an appropriate reserve balance is determined, an accrual that will maintain this level in the reserve can be established.

The analyses performed and the results provided for Tampa Electric's reserve are consistent with the intent of the FPSC rule and provide appropriate metrics to consider for the reserve's performance.

Q. What did your evaluation show with respect to a $50.2 million initial reserve balance and an $8 million annual accrual?

A. It showed that the reserve value of $50.2 million combined with annual accruals of $8 million is too small to pay for most storm damage. In fact, it is too little to pay for all SSI 1, also referred to as Category 1 (SSI 1) or Category 2 (SSI 2, also referred to as Category 2) single storm events.

Figures 4-2 through 4-5 of the Storm Study show the mean (or average) damage from single hurricane events of the same intensity category SSI 1 through SSI 4 that make landfall within 10 mile intervals along the Gulf Coast in and around Tampa Electric's service area. Also shown are the initial (Year 0) and final (Year 5) balance values of the reserve from the EQECAT Reserve Performance Analysis for comparison with the potential hurricane damage. The reserve analysis shows the reserve balance to decline in each year from its initial value of $50.2 million until it reaches a negative ($5,575,080) at Year 5. The reserve will have about a one in three chance of having inadequate funds over the five year period.

With a reserve balance of $50.2 million the reserve would be inadequate to cover all single average SSI 1 hurricane landfall damage. The damage values from these figures are the mean or average of all hurricane events in the intensity category. The maximum hurricane damage levels at milepost 1,210 (near St. Petersburg) for SSI 1 and SSI 2 events are approximately $62 million and $178 million, respectively. A reserve balance of $50.2 million at Year 0, or a negative ($5,575,080) at Year 5, is inadequate to cover either of these worst case SSI 1 and SSI 2 events.

The potential damage from Category 1 through Category 4 storms in the Storm Study at these landfall mile posts show that the projected reserve would not be adequate to cover the maximum estimated damage associated with Category 1 through Category 4 storms.

Even if Tampa Electric has favorable storm experience over the following five years, the reserve balance could only grow to $83,374,000. This reserve value is larger than the maximum Target Range of $64,000,000 authorized by the FPSC. More significantly, a $83,374,000 reserve balance would be less than half of the expected damage from the worst SSI 2 storm at landfall 1,210.

The reserve will not, however, be able to fund all SSI 1 or SSI 2 storms without higher accruals for the reserve, or a higher Target Range than currently authorized, along with more years of favorable storm experience.

Were the reserve to be adequately funded for SSI 1 and SSI 2 storms, it would still be far below the levels of damage that might be expected from SSI 3 and SSI 4 storms. Average damage from these events as shown in Figure 4 and 5 can be in excess of $250 million to $500 million with the maximum damage being much greater than

these average values.

Q. Why didn't you factor the Storm Hardening activity into the damage estimates in the Storm Study?

A. The Tampa Electric Storm Study did not evaluate the effects of the Storm Hardening Program. The decisions on the scope of the Storm Study were made in 2011 when Tampa Electric was formulating the scope for planning and budgeting purposes. At the time, the Storm Hardening Program was less than half way through implementation of the decade long program. It is believed that the Storm Hardening Program will, when completed, reduce the impact of hurricane damage on the system. At the time, Tampa Electric had experienced six consecutive storm years without any significant losses, and therefore data on the effectiveness of the Storm Hardening Program was not available.

At present, in the absence of actual hurricane experience with storm hardening to the system, a reliable estimate of the possible impact of the Storm Hardening Program on hurricane damage to Tampa Electric's transmission and distribution system is speculative.

For the sake of illustration, a rough order of magnitude estimate of the impact of the storm hardening activities might look like the following. At present, the total, actual and planned, expenditures for the Storm Hardening Program are expected to be $458 million, or about 11 percent of the 2011 replacement value of Tampa Electric's transmission and distribution system assets. By making a large assumption, that the storm hardening activities will preclude any future hurricane damage to the assets involved in the Program, this could represent up to about a 10 percent reduction in damage, once the Program implementation is completed. This hypothetical illustration would represent about a maximum of $2 million per year reduction in the expected annual damage to the system of $21.9 million.

With these assumptions, the best case outcome might be an expected annual damage reduction from $21.9 million to $19.7 million, with $15.8 million of the expected annual damage being an obligation to the reserve. This illustration is, speculative, and a more reliable estimate of the effects of the Program would require further simulation modeling analyses that would incorporate the details of the Storm Hardening Program activities, and data from actual hurricane events with

storm hardening to the system.

Q. Please summarize your rebuttal testimony.

A. The averaging method proposed by witnesses Shultz and Pollock, considering only the 2000 to 2012 hurricane seasons, excluding the 2004 storm season, does not provide a meaningful estimate of annual damage to Tampa Electric's transmission and distribution system, and does not provide probabilities of damage.

The EQECAT Storm Loss Analysis performed for Tampa Electric's transmission and distribution system uses a storm simulation model, which is the current and most reliable methodology in the insurance industry, to estimate storm damage costs and probabilities of occurrence. The expected (or average) annual storm damage is estimated to be $21.9 million.

The damage estimates and probabilities are used to simulate the financial performance of the reserve over a prospective five year period given an initial balance, annual accruals, and losses that would be paid from the reserve with an average of $17.6 million per year consistent with FPSC rules. The result of this simulation

analysis shows that the mean reserve balance will decline from the initial $50.2 million at Year 0, to a negative ($5,575,080) at Year five.

The reserve will have about a one in three chance of having inadequate funds over the five year period. The reserve, in the early years of the simulation, would cover the cost of some but not all single Category 1 storms that might affect Tampa Electric's system. At year five of the simulation, the reserve will likely have inadequate fund to cover storm damage.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION FOR AN INCREASE IN BASE RATES

AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY

OF

EDSEL L. CARLSON, JR.

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

EDSEL L CARLSON, JR.

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

A. My name is Edsel L. Carlson, Jr. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Risk Manager for Tampa Electric Company ("Tampa Electric" or "company").

Q. Are you the same Edsel L. Carlson, Jr. who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors and shortcomings in the prepared direct testimony of witness Helmuth W. Schultz III, who is testifying on behalf of the Office of Public Counsel, ("OPC") and witness Jeffry Pollock, who is testifying on behalf of

The Florida Industrial Power Users Group ("FIPUG").

Q. Please summarize the key concerns and disagreements you have regarding the substance of witnesses Shultz's and Pollock's testimonies.

A. My key concerns and disagreements are as follows:

1. I disagree with witness Shultz that the company's requested storm accrual amount and reserve target is not supported by historical storm activity.
2. I disagree with witnesses Shultz and Pollock that the effects of storm hardening should have an impact on the requested $8 million accrual amount and that improper assumptions were used.
3. Although I do agree with witness Shultz that other options exists to recover storm costs, the surcharge option provided by witness Shultz is more costly and less beneficial to customers than the company's proposed reserve.
4. I disagree with witness Pollock's assertion that "It is clear that customers prefer to pay when the damage occurs…" Additionally, witness Pollock's statement that "TECO is seeking to establish the reserve at a level designed to provide for coverage for all storm damage" is erroneous.

STORM DAMAGE RECENT STORM HISTORY

Q. Do you agree with witness Schultz that historical storm activity does not support maintaining the $8 million annual accrual and the requested $100 million target reserve amount?

A. No. As a preliminary matter, I disagree that the company's 10-year storm loss history should be used to set the company's storm damage expense accrual or storm damage reserve. The Storm Study ("Study") performed by witness Steven P. Harris on behalf of Tampa Electric is the kind of study used by the insurance industry and its underwriters and is the best tool available to evaluate the company's proposed storm accrual and reserve target. Witness Harris' rebuttal testimony explains this further.

However, if the Commission wants to use historical averages as a high level test of the reasonableness of the company's proposed accrual, Tampa Electric's 10-year storm loss history supports maintaining the current $8 million accrual. As described in my direct testimony on page 5 and including a recent charge to the reserve in 2013 for Tropical Storm Isaac, the annual amounts charged against the reserve for storm damage in the last ten years have been as follows:

2004 = $73.4 million

2008 = $1.6 million

2011 = $1.9 million

2012 = $1.2 million

2013 = $0.9 million

Total = $79 million

The $79 million total translates to approximately $8 million a year on average over the last ten years. Although the study performed by witness Harris suggests that a higher annual accrual amount would be reasonable, the company is proposing to maintain its annual accrual at the $8 million approved by the Commission in Tampa Electric's last rate proceeding.

Q. Do you believe that the amounts incurred by the company in 2004 should be disregarded when computing the 10-year average?

A. No. While the 2004 storm season certainly has the greatest impact on the on the 10-year average, that year was not unusual. As shown in witness Harris' Storm Study there is an 8.68 percent probability that there will be damage in any one year that exceeds $60 million. Likewise, as witness Pollock acknowledges, the Storm

Study statistically supports the notion that a storm inflicting damage in an amount in excess of $60 million is likely to occur once every 11.5 years. This probability supports Tampa Electric's need to increase its target from $64 million to $100 million because if the company were to experience this level of storm damage today the current reserve would be inadequate.

Q. Do you agree with witness Schultz that the 2004 storms were an anomaly and are not the type of storms to be covered by the reserve?

A. No. Three hurricanes affected Tampa Electric in 2004, but none of the storms made landfall in Tampa Electric's service territory; they were glancing blows. All three storms had wind speeds in Tampa Electric service territory that were near or below the threshold of hurricane strength and Tampa Electric still experienced over $73 million in storm damage. These events are exactly the type of storms that should be covered by the reserve. The company's experience in 2004 supports Tampa Electric's request to increase its target reserve to $100 million. That target level will allow the company to cover most but not all storms events and to adequately protect customers from surcharges after storm events.

If any of the three 2004 storms had made landfall in or tracked directly through Tampa Electric service territory, the storm losses in 2004 would have been significantly greater. For example, Hurricane Charley actually hit near Punta Gorda, approximately 50 miles south of Tampa Electric's service territory. If Charley had made landfall closer to the mouth of Tampa Bay, the loss to Tampa Electric's transmission and distribution ("T&D") system could have been in the hundreds of millions of dollars. Tampa Electric is not proposing an accrual or reserve patterned around this type of event but the reality is that a significant exposure to loss from hurricanes exists for the company.

STORM HARDENING AND OTHER ASSUMPTIONS IMPACT ON STORM STUDY

Q. Do you agree that the proposed accrual amount should be adjusted for the effects of storm hardening?

A. No. The Study prepared by witness Harris is reasonable based on the historical information available at the time the Study was prepared. As witness Harris explains in his rebuttal testimony, it may be possible to factor the impact of storm hardening activities into future studies, but the estimated impact of doing so would not be material to the decision in this case, because the

company's proposed annual accrual level is less than half of the estimated annual loss reflected in the Study.

Q. Do you agree with witness Schultz that the 4.5 percent annual cost increase for T&D assets contained in the Study is too high?

A. No. Witness Shultz's criticism has no merit. He fails to consider system growth, and bases his criticism on recent rates of inflation that are low from a historical perspective.

Q. Please explain how the company developed the 4.5 percent annual cost increase for T&D assets and why that assumption is reasonable and appropriate.

A. The basis for the 4.5 percent annual cost increase for T&D assets was Tampa Electric's five year average annual historical replacement cost increase to its total T&D assets from 2007 to 2012. Tampa Electric computed this percentage by comparing its total T&D replacement value in 2007 to the values in 2012 and calculated that the values increased due to inflation and system growth by a little over 22 percent over the five year period, or an average of approximately 4.5 percent a year. Tampa

Electric assumes that its system's replacement value will grow in the next five years similarly to how it did in the last five years. It is important to note that the 4.5 percent includes both inflation and system growth. Tampa Electric believes this assumption is reasonable.

CUSTOMER IMPACTS AND OTHER OPTIONS

Q. Do you agree with witness Pollock that Tampa Electric's Customers do not benefit from a higher Reserve Target and that there are other options besides a storm reserve?

A. No. Tampa Electric believes that its customers are better served by an adequate reserve built gradually over time than by an emergency surcharge after a catastrophic event. Tampa Electric believes it is very important to try to avoid imposing a surcharge to a customer that has been affected by a storm event. After a storm event, customers will be dealing with their own storm recovery efforts and may incur substantial cost associated with insurance deductibles and increased insurance premiums that will usually follow for several years into the future. This makes right after a storm the worst time to impose a surcharge and increase costs to customers.

As noted in my direct testimony, the company has a storm

reserve because T&D insurance is unavailable at reasonable terms and pricing. If the company could purchase T&D property damage insurance at reasonable prices, the company would pay a premium each year that would be part of our cost of doing business and properly included in cost of service. The insurance premium cost would be paid by all customers regardless of a loss event or not, just like the other insurances that Tampa Electric is able to purchase. The annual storm accrual is very much like the T&D insurance premium it has replaced, and is a cost of doing business in Florida and should be paid by the customers receiving the benefit from the protection of the reserve.

Q. Do you agree with witness Pollock that customers would prefer to pay a surcharge after the storm event?

A. No. First, witness Pollock's view is not supported by any real evidence of customer preferences, but rather a statement from intervenors representing customers that they would rather pay to fund the reserve to a lower level now and risk future rate volatility. Second, based on the reaction that customers have when electric rates increase due to fuel cost increases and other similar items, the company believes that a post-storm surcharge

would face opposition from many customers.

Q. Witness Schultz noted that Tampa Electric is now requesting a target of $100 million and in 2008 it requested $120 million. Please explain the reduction in the requested target amount.

A. Tampa Electric believes that it is important to establish a reserve target level that will cover the higher probability lower severity storm events. The company believes this to be primarily Category 1 and 2 hurricane storm events. Tampa Electric used the information supplied in the Storm Studies to establish the requested storm target reserve. The hurricane landfall analyses in the 2013 Study showed that the average loss for a Category 2 hurricane directly hitting the company's service area would be approximately $118 million. In the 2008 Study, the estimate was approximately $130 million. The reduction in the requested target amount was based on the results of the landfall analysis in the Storm Studies.

Q. Do you agree with witness Pollock's statement that Tampa Electric is seeking to establish the reserve at a level designed to provide for coverage for all storm damage?

A. No. Tampa Electric is requesting a target reserve level adequate to cover most Category 1 and 2 hurricane events. The company is not proposing an accrual or reserve patterned around low probability events like a Category 3 or 4 direct hit. The potential for average damage in those events is over $300 million for a Category 3 hurricane and could be over $600 million for a Category 4 hurricane.

Q. What is the target reserve Tampa Electric is requesting and what is the basis for that amount?

A. Tampa Electric is requesting that the target reserve be increased from $64 million to $100 million. The basis for this request is that T&D values have increased by more $700 million since the Commission established the reserve target in 2008. Also, and more importantly, the result of witness Harris' Study demonstrates that the reserve should be increased to adequately cover most but not all storm events (Category 1 and Category 2 events). Figure 4-3 of The Hurricane Landfall Analyses contained in the Storm Study shows that if a Category 2 hurricane event directly hits the company's service area the average amount of damage to Tampa Electric would be approximately $118 million. It is important to note,

that this estimated loss amount is the average amount of all simulated storm events hitting a particular mile post marker. It is my understanding, in discussions with witness Harris, that the range on those losses is large. He explains in his rebuttal testimony that the maximum hurricane damage from a Category 1 hurricane directly hitting Tampa Electric's service territory is approximately $62 million and $178 million for a Category 2.

Summary of Rebuttal Testimony

Q. Please summarize your rebuttal testimony.

A. Tampa Electric's annual storm damage accrual should remain at $8 million in order to build its storm damage reserve to a level sufficient to provide for most, but not all, storms and the target reserve balance should be increased to $100 million. While a larger accrual amount is supported by the Storm Study prepared by witness Harris, the $8 million annual accrual minimizes customer rate impacts. Despite a 10-year period of favorable storm experience and no direct hits from a hurricane to the company's service area, the company has still incurred $79 million in storm damage losses over that period, which translates to approximately $8 million per

year. Finally, I believe the intent of the reserve is to cover most but not all storm events, which represents tropical storms as well as Category 1 and Category 2 hurricanes. As such, the company has requested to increase the target reserve amount to $100 million since witness Harris' Study shows the average amount of damage to Tampa Electric from a Category 2 hurricane would be approximately $118 million.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION FOR AN INCREASE IN BASE RATES

AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY

OF

JEFFREY S. CHRONISTER

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

JEFFREY S. CHRONISTER

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

A. My name is Jeffrey S. Chronister. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as its Controller.

Q. Are you the same Jeffrey S. Chronister who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors and improper conclusions in the prepared direct testimonies of Steve Chriss, testifying on behalf of the Florida Retail Federation ("FRF"); Michael Gorman, testifying on behalf of the Federal Executive Agencies

("FEA"); Lane Kollen, testifying on behalf of the WCF Hospital Utility Alliance ("HUA"); Helmuth Schultz, Jacob Pous and Donna Ramas, testifying on behalf of the Office of Public Counsel ("OPC"); and Jeffry Pollock, testifying on behalf of the Florida Industrial Power Users Group ("FIPUG").

KEY CONCERNS

Q. Please summarize the key concerns and disagreements you have regarding the substance of the testimonies of witnesses Chriss, Gorman, Kollen, Schultz, Pous, Ramas, and Pollock.

A. My key concerns and disagreements relate to the following topics:

- Projected Test Year
- Capital Structure Adjustments
- Interest Synchronization
- Construction Work in Progress ("CWIP") in Rate Base
- Other Operating Revenues
- Intangible Plant - Software Amortization
- O&M Expense
- Bad Debt Expense/Reserve for Uncollectable Accounts
- Rate Case Expense
- Injuries & Damages ("I&D") Expense

- Legal Expenses
- Other Post-Retirement Employee Benefits
- Stock Compensation Expense
- Parent Allocation

PROJECTED TEST YEAR

Q. FRF witness Steve W. Chriss indicates concern regarding the company's use of a projected test year. Do you agree with his position?

A. No. Although the use of a projected test year is not required by rule or statute, the Commission has extensive experience using projected test years going back to the 1980's. Most recently, the Commission approved Tampa Electric's use of a projected test year in the company's last base rate proceeding in Docket No. 080317-EI.

Q. Is use of a projected test year consistent with decisions made by the Commission for other utilities?

A. Yes. The Commission has used projected test years for Tampa Electric's 1992 base rate proceeding, Gulf Power Company's 2011 base rate proceeding and many others. The Commission authorized Florida Power & Light ("FPL")

to implement a revenue increase based on a projected test year (2013) in Order No. PSC-13-0023-S-EI, issued on January 14, 2013 in Docket No. 120015-EI.

Q. Why is the use of a projected test year appropriate in general and in this case?

A. Using a projected test year properly matches revenues with the capital and operating costs to be incurred in future periods. Basing a request on a projected test year is appropriate because the test year best represents operational and business conditions that will be present during the time the new rates will be in effect.

Q. Does the financial information for 2014 presented to the Commission in the minimum filing requirements form a reasonable basis for calculating the company's 2014 revenue requirement and for setting customer base rates?

A. Yes. I provide a detailed explanation of the company's budget process in my direct testimony.

CAPITAL STRUCTURE ADJUSTMENTS

Q. FEA witness Gorman proposes on pages 17 through 20 of

his testimony a revised capital structure that allocates pro forma adjustments across only investor sources of capital. Do agree with this approach?

A. No. This approach is not appropriate nor is it consistent with recent decisions by the Commission.

Q. Please explain.

A. In the Motion for Reconsideration from the company's last base rate proceeding, Order No. PSC-09-00571-FOF-EI, the Commission concluded that rate base plant adjustments should be removed by a pro rata adjustment over all sources of capital.

Q. What was the Commission's treatment for non-plant adjustments in the company's 2008 base rate proceeding?

A. Non-plant items were removed through a pro rata adjustment over investor sources of capital.

Q. Has the Commission ruled on non-plant adjustments more recently?

A. Yes. More recently, the Commission has ruled that all

pro rata adjustments should be made over all sources of capital. This approach was approved by the Commission in the most recent rate proceedings for Progress Energy Florida ("PEF") and Gulf Power Company ("GPC"). The PEF ruling was in Order No. PSC-10-0131-FOF-EI, issued on March 5, 2010 in Docket Nos. 090079-EI, 090144-EI, and 090145-EI. The GPC ruling was in Order No. PSC-12-0179-FOF-EI, issued on April 3, 2013, Docket No. 110138-EI.

Q. What was the rationale for the Commission's decisions to make pro rata adjustments over all sources of capital?

A. The Commission's primary rationale is to avoid a tax normalization violation. The Commission decisions also reflect the regulatory efficiency associated with making all pro rata adjustments over all sources of capital. Witness Terry Deason provides additional information and historical context on this issue in his rebuttal testimony on behalf of Tampa Electric Company.

Q. Do you have any other issues with witness Gorman's proposed capital structure as reflected on his exhibit MPG-1?

A. Yes. Witness Gorman has inappropriately omitted the

capital structure adjustment to adjust equity for common dividends payable (which is shown in Column 2 of Schedule D-1a in the amount of $13.4 million). This amount represents the 13-month average of the dividends declared but not yet paid. Since the cash payments have not yet been made, it is proper to reflect this amount as equity.

Q. Does this treatment reflect prior Commission decisions?

A. Yes. The Commission has consistently supported this adjustment for ratemaking purposes because it properly reflects the actual equity position of the company. The Commission included this adjustment in the calculations supporting their Order in the company's 2008 base rate proceeding. Also, the Commission indicated the following in its Order for Tampa Electric's 1992 base rate proceeding (Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, Docket No. 920324-EI):

> The Commission has consistently increased equity and the working capital allowance reversing the average balance of common stock dividends payable. TECO has filed its request consistent with this method, treating common stock dividends as a component of capital structure.

INTEREST SYNCHRONIZATION

Q. OPC witness Donna Ramas indicates on page 29 of her testimony that an interest synchronization adjustment is needed since OPC's proposed amounts differ from the company's proposed amounts. Do you agree with the dollar amount of her interest synchronization adjustment?

A. No. However, I do agree with witness Ramas's position that after final rate base and weighted cost of debt decisions are made by the Commission a new interest synchronization adjustment will need to be made. It appears that all parties agree on the consistent method of synchronization.

CONSTRUCTION WORK IN PROGRESS (CWIP) IN RATE BASE

Q. Is Tampa Electric's requested level of CWIP in the amount of $174,146,000 for the 2014 projected test year appropriate?

A. Yes. It is reasonable and necessary. It properly reflects the budgeted amount for the 2014 test year.

Q. FRF witness Steve W. Chriss states on page 8 of his testimony that the Commission should reject the

company's request to include $174.1 million of construction work in progress in rate base. Do you agree with this statement?

A. No. Witness Chriss's position is contrary to long-standing Commission practice and inconsistent with sound regulatory policy. The long-standing practice of the Commission has been to allow CWIP in rate base for the short-term CWIP that is not eligible for Allowance for Funds Used During Construction ("AFUDC") under Florida Administrative Code ("F.A.C.") Rule 25-6.0141 Allowance for Funds Used During Construction (New Rule 8/11/86). I will refer to this type of CWIP as "CWIP Not Eligible for AFUDC" hereinafter. Witness Terry Deason provides additional information and historical context on this issue in his rebuttal testimony on behalf of Tampa Electric Company.

Q. Please provide more detail on the rule and the Commission's historical practice.

A. The rule limits AFUDC eligibility to projects that are: (a) not included in rate base, (b) involve gross additions to plant in excess of 0.5 percent of the sum of the total balance in Account 101 - Electric Plant In

Service, and Account 106 - Completed Construction Not Classified, at the time the project commences and (c) are expected to be completed in excess of one year after commencement of construction. The Commission practice of allowing CWIP Not Eligible for AFUDC in rate base and limiting AFUDC to very large projects minimizes rate base in the long-term. Surveillance reporting includes CWIP Not Eligible for AFUDC in rate base and excludes CWIP earning AFUDC from rate base. As witness Terry Deason explains further in his rebuttal testimony on behalf of Tampa Electric, sound regulatory policy recognizes that if CWIP Not Eligible for AFUDC is not allowed in rate base, this CWIP should be provided a return by making it eligible for AFUDC. However, the Commission practice has been to include CWIP Not Eligible for AFUDC in rate base (rather than including it in AFUDC calculations) to provide the return.

Q. Has the Commission previously approved including CWIP Not Eligible for AFUDC projects in rate base as proposed by the company?

A. Yes. Including CWIP Not Eligible for AFUDC in rate base has been the Commission's practice for many years and the Commission approved that approach in the company's

last rate proceeding. The company's proposed treatment of CWIP Not Eligible for AFUDC in this case is consistent with the Commission's ruling in the company's last rate proceeding.

OTHER OPERATING REVENUES

Q. OPC witness Ramas states on page 10 of her testimony that she is not recommending an adjustment for Auburndale Power Partner wheeling revenue. Do you agree with this position?

A. Yes. There is no change to date to the Auburndale Power Partner ("APP") commitment and there is no indication from APP that this will change. At this time the company does not expect any additional revenue from APP and no adjustment is necessary.

Q. While discussing proposed adjustments related to the change in the status of the Calpine contract, witness Ramas notes on line 1 of page 9 of her testimony that the reason for some revenue treatments are not clear. Can you provide a clarifying explanation?

A. Yes. In Tampa Electric's initial filing, for the year 2014, the company wanted to provide a more transparent

presentation of revenues from wholesale transmission agreements. The final retail jurisdictional other operating revenues of $42,854,000 should not include (and do not include) wholesale transmission revenues. In an effort to clearly delineate amounts, the company included in "Per Books" (Column 1) of Schedule C-5 the wholesale transmission revenues. The company then removed from lines 26 and 29 the Calpine and Auburndale revenues (Columns 10 and 11) as Jurisdictional Adjustments. On Schedule C-2 page 3 of 7 (Columns 2 and 3), these jurisdictional adjustments are reflected as "Company Adjustments" - due to the company's decision to have a more transparent presentation.

Q. Are there references in witness Ramas' testimony to your MFR treatments that need to be corrected?

A. Yes. At the top of page 9 of witness Ramas' testimony she indicates that Calpine revenues were reflected as jurisdictional revenues in Tampa Electric's filing. As stated above, the wholesale transmission revenues are not part of jurisdictional other operating revenues. I recognize that the company's MFR presentation described above left room for confusion. However, I think that the statements made in witness Ramas' testimony reflect

her position that normal treatment for wholesale transmission revenue is exclusion from jurisdictional amounts. Tampa Electric agrees with that position.

Q. Are any other clarifications needed?

A. Yes. The company proposed (and continues to propose) to adjust separation factors to properly reflect the costs which should be associated with Tampa Electric's wholesale transmission agreements - and their most recently confirmed volumes. Wholesale transmission revenues should be excluded from retail revenue requirement calculations. But retail revenue requirement calculations should be adjusted by the most recently known information about volumes that impact cost separation. It appears that all parties agree on these concepts.

INTANGIBLE PLANT - SOFTWARE AMORTIZATION

Q. OPC witness Pous on page 3 lines 4 through 19 of his testimony under "what is the purpose of your testimony?" proposes (1) a 15-year amortization period for all software and (2) an increase from $3.327 million to $5.271 million for the amortization reserve for the Enterprise Resource Planning ("ERP") software system.

Do you agree with these proposals?

A. No. In describing the purpose of his testimony, witness Pous addresses two issues. The first issue witness Pous addresses is the company's proposal for continuation of a five-year amortization period for the vast majority of the investments in its software systems and a request for a 10-year amortization for its newly installed ERP software system. Witness Pous recommends adjusting these amortization periods to 15 years. Witness Pous provides no study or support for his recommendation. The second issue witness Pous addresses relates to the level of amortization reserve associated with the company's newly installed ERP software system. He states that the company has booked amortization expense into the accumulated provision for amortization through the end of 2014 based on a 10-year amortization period. He asserts that the Commission has only approved a five-year amortization period for software in prior proceedings.

Q. Do you agree with these positions?

A. No. The five-year amortization period was not at issue in the company's last rate proceeding. The Commission

has not addressed amortization of software in the company's depreciation orders or studies. The amortization periods proposed by the company in this case were filed with the Federal Energy Regulatory Commission ("FERC") and were accepted in two wholesale settlement agreements. The company's proposed amortization over 10 years is reasonable and appropriate.

Q. Why did the company not seek approval of a 10-year amortization period for the new ERP system when it filed its depreciation study with the Commission in April 2011?

A. The company follows the long-standing practice of the Commission that the Depreciation Rule 25-6.0436, F.A.C. applies to depreciable tangible property and not to intangible property like rights, consents and software. The company has never requested an amortization period for software in its petitions to change depreciation rates and the Commission and staff have never requested such proposals. To its knowledge, the company has not seen any other Florida electric investor-owned utility file proposals for software amortization in their depreciation studies.

The company believes that the Commission's exclusion of software amortization periods from depreciation study requirements is appropriately based on the fundamental differences between tangible and intangible assets. Tangible assets require physical removal and disposal. Depreciation studies can use that activity to analyze service lives and net salvage factors. Software is a set of computer codes that does not require physical removal when taken out of service. To more efficiently account for software additions and retirements, the company adds new software systems or upgrades to Account 303 (Intangible Property) and amortizes the cost over the amortization period. The cost is retired when the intangible asset is fully amortized.

Q. What period has the company historically used for amortizing software?

A. The company has historically used a five-year amortization period and this period is still appropriate for most software systems. Software upgrades occur about every five years and often replace initial configuration and add new functionality. Support of the system by vendors is dependent on implementing new versions of the software.

Q. Then why has the company proposed using a 10-year period for amortizing the cost of its new ERP system?

A. The new ERP system is significantly different from previous software systems in the magnitude and breadth of its functional scope. The company - through industry surveys - has seen that many investor-owned utilities ("IOU") use between 10 to 12 year amortization periods for major ERP Systems and five years for smaller software systems. Witness Pous recognizes the 10 to 12-year amortization periods used by other companies on page 20 lines 13 and 14, referring to them as: "…the realistic lower-end level 10- to 12-year life proposed by some other utilities for major software systems."

Q. What has the Commission accepted in other cases for software amortization lives?

A. In PEF's Docket No. 090079-EI, the company proposed the following rates/lives for software systems: Corporate - Misc. Intangible 303 - 20 percent (5 years), CSS Intangible 303 - 10 percent (10 years) and Transmission Intangible 303 - 14.29 percent (7 years) (MFR Schedule B-7 Plant Balances by Account and Sub-Account, page 10 of 28, rows 5 through 8, column B). In Order No. PSC-

10-0398-S-EI, issued on June 18, 2010 [Order Approving Stipulation and Settlement] the proposed amortization lives were not changed.

On page 20 lines 5 through 8, witness Pous states that FPL, in its recent rate proceedings, proposed changing the amortization lives from 5 years to 20 years for its new general ledger accounting software system; however, he fails to mention that FPL continues to use five years for all other software systems.

GPC has consistently used seven years for their software amortization period.

The Commission has recognized the impact on technological tangible assets of technological obsolescence in its approval of lives between three to seven years for personal computer workstations, servers, telecommunication equipment and even tools, furniture and fixtures. Witness Pous's proposed 15-year amortization period for all software projects is inconsistent with the amortization periods approved in other Orders.

Q. On pages 9 through 11, witness Pous opines, "the

company's admission that it has not performed any such studies demonstrates not only the lack of support for the company's proposal, but also a violation of FERC's current requirement guidelines." Do you agree with this position?

A. Absolutely not. Throughout his testimony, witness Pous quotes requirements for depreciation and substitutes the word software as if they are synonymous. As mentioned previously, the F.A.C. Rule 25-6.0436 [Depreciation] does not mention "amortization". F.A.C. Rule 25-6.04361 [Subcategorization of Electric Plant for Depreciation Studies and Rate Design] does not list Account 303 - Miscellaneous Intangible Plant as a required category for depreciation studies. The company has filed depreciation studies since the late eighties and has never filed an engineering study for software assets. No Florida IOU has filed an engineering study for software assets. The Commission has accepted all of Tampa Electric's depreciation studies as being in compliance with the depreciation rules. The company filed Section 205 filings to get FERC approval for the Commission Order on change in depreciation rates as well as the 5- and 10-year software amortization periods for two wholesale rate cases. Neither FERC nor the

interveners objected to the company's amortization periods for software. That is strong proof that the company did not violate any FERC or Florida rules associated with this issue.

O&M EXPENSE

Q. Several intervener witnesses have suggested that the operations and maintenance ("O&M") requested in this proceeding should be reduced because it is higher than historical amounts from the last three years. Is this approach reasonable?

A. No. Witness Kollen proposes to adjust generation O&M based on a 3-year historical average level of expenses. Witness Kollen also proposes to adjust transmission and distribution ("T&D") expenses based on the 2012 historical level of expenses. This backward-looking approach results in a negative outcome for positive business practices.

Q. Please explain.

A. The company has worked hard to control costs. If historical costs are used to set future rates, then the company is negatively impacted by its own efforts to

take steps to benefit the customer. More importantly, making a backwards looking adjustment based on historical averages using years of abnormally low spending effectively locks in spending levels that are not sustainable.

Q. How do company cost control efforts benefit customers?

A. In two ways: (1) In periods of low revenue, cost control efforts allow the company to maintain financial health; thus, the company can go longer without asking the Commission to increase rates. (2) Many cost control efforts eliminate or temper future cost increases. Cost control efforts that lower future costs in turn lower future revenue requirements.

Q. Can you give an example of this?

A. Yes. The company implemented several process and system improvements that significantly lowered bad debt expense. The Commission approved $8 million for this expense in the company's base rate proceeding five years ago. In that year, the company incurred over $7.5 million of expense. In this proceeding the company is asking to recover 2014 expense of $3.6 million. Tampa

Electric's efforts to reduce bad debt expense are detailed in rebuttal testimony Tampa Electric witness Karen J. Lewis. She also explains why the Commission should not make an adjustment to lower bad debt expense in the 2014 projected test year.

Q. Various intervener witnesses have criticized the total level of the company's 2014 O&M expenses as well as specific components of 2014 O&M expenses. Do you agree with their observations and criticisms?

A. No. I believe the intervener witnesses have improperly evaluated the company's proposed O&M expense levels for 2014.

Q. Please explain.

A. First, I think it would be helpful to put the company's proposed level of O&M spending in the proper perspective. In the company's last base rate proceeding, the Commission approved a total jurisdictional amount of O&M expense of approximately $355 million for the 2009 test year. The company's proposed total jurisdictional O&M expenses for the 2014 test year in this proceeding is $364 million, only $9

million more than the level approved for 2009. I hope the Commission will consider this overall level of spending for 2014 to be reasonable and to keep this overall spending level in mind as it evaluates the specific O&M adjustments proposed by the interveners.

Second, as I mentioned above, I believe that the interveners have inappropriately relied on historical averages when calculating the dollar amounts of certain adjustments. The Commission should reject this approach to evaluating and adjusting proposed O&M expense levels because the historical averages used by the interveners include two atypical years - 2011 and 2012 - when the company dramatically cut spending to unsustainably low levels in light of unforeseen and unprecedented revenue shortfalls. Including these unusually low spending years in the average and computing an adjustment based on the average yields a result that "locks in" unsustainably low spending levels and will impair the company's ability to provide safe and reliable service to its customers.

Third, as explained by rebuttal witness Terry Deason on behalf of Tampa Electric, the "looking backwards" approach to evaluating O&M expense spending levels is

inconsistent with the idea of a projected test year.

Finally, I am concerned about the high level approach to adjusting O&M expense levels advocated by the interveners. Although averages and benchmarks can be useful tools for organizations to use in high-level analysis of spending, the intervener witnesses have not identified any particular operational activity that the company should forego. For example, while witness Schultz is proposing that the company's headcount be reduced by 114 people, he has not identified a single position that the company should not add. Likewise, in the operations areas, the intervener witnesses have not identified any particular aspect of generation maintenance, call center operation or any other particular business activity that the company should not pursue. I would suggest that the company's operational witnesses are in the best position to assess and explain the level of spending the company needs to provide safe and reliable service to our customers.

BAD DEBT EXPENSE/RESERVE FOR UNCOLLECTIBLE ACCOUNTS

Q. HUA witness Kollen states on pages 28 and 29 of his testimony that the increase in uncollectable accounts expense is excessive and should not be recovered. Do

you agree with this position?

A. No. First, the budget for bad debt expense increases less than $600,000 from 2013 to 2014. More importantly, the 2014 projected amount is well below actual annual expense incurred from 2007 to 2011. It is true that the 2012 expense was low as the company implemented new processes and technology to capture substantial uncollected dollars. However, focusing on the unique low expense in one year does not make sense. Instead, the 2014 budget of $3.6 million can be put into context by examining the following actual amounts:

2007 -	$5.5 million
2008 -	$6.8 million
2009 -	$7.5 million
2010 -	$7.8 million
2011 -	$4.1 million

Finally, the bad debt expense proposed by Tampa Electric is actually $4.3 million lower than the amount used by the Commission to set rates five years ago. Tampa Electric's projected expense is reasonable and appropriate.

Witness Lewis explains the activities undertaken by the

company in the last several years to manage bad debt expense.

RATE CASE EXPENSE

Q. OPC witness Schultz asserts that the company's rate case expense request is excessive. He argues that since the company is not small it should be able to assemble a rate filing without significant assistance. Do you agree with this statement?

A. No. Much like the interveners, who have retained outside resources to assist in preparing their case, Tampa Electric has retained consultants to serve as expert witnesses and assist in case preparation. With the significant discovery submitted by interveners in this particular proceeding, the need for outside help has been even greater. The company is staffed to handle on-going, day-to-day responsibilities, so the additional workload of the rate filings requires supplementing the existing team. To do otherwise would be costly to customers.

Q. Witness Schultz recommends that rate case expense should be amortized over five years rather than three. Do you agree?

A. No. Based on the Need Determination approved by the Commission in Docket No. 120234-EI in Order No.PSC-13-0014-FOF-EI, issued on January 8, 2013, Tampa Electric will be investing in base load generation at the Polk Power Station. This will likely require the company to seek rate relief within three years to recover prudent costs associated with this significant project. Given the timing of the company's next base rate proceeding filing, three years is an appropriate amortization period for rate case expense and no adjustment should be made.

INJURIES & DAMAGES EXPENSE

Q. HUA witness Kollen states on page 25 of his testimony that injuries and damages expense should be reduced by $1.728 million to reflect historical experience. Do you agree with this position?

A. No. First, injuries and damages ("I&D") expense - both actual and budgeted - is the result of recommendations from outside actuaries. The actuaries use historical loss experience but also consider many current and future factors that would properly go into an analysis of this type of liability. In addition, the I&D expense proposed is only about $250,000 higher than the 2012

actual amount - and about $400,000 lower than the amount used by the Commission to set rates five years ago. Tampa Electric's projected expense is reasonable and appropriate.

LEGAL EXPENSES

Q. HUA witness Kollen states on pages 29 and 30 of his testimony that the increase in legal expense is excessive and proposed recovery should be reduced by $1.521 million. Do you agree with this position?

A. No. First, the budget for legal expense increases less than $200,000 from 2013 to 2014. The 2014 projected amount is reflective of circumstances that will be present during the time that future rates will be in effect. They also involve on-going efforts to reduce costs to be borne by customers - as well as protect revenues that lower revenue requirements for customers. Legal expense projected for 2014 is reasonable considering actual expense over the last five years. Finally, the legal expense proposed by the company is less than $900,000 greater than the amount used by the Commission to set rates five years ago. Tampa Electric's projected expense is reasonable and appropriate.

Q. HUA witness Kollen and OPC witness Ramas suggest that $520,000 included in projected test year expenses for the pending litigation with Verizon regarding pole attachment charges be removed. Do you agree with this position?

A. No. The company expects to continue incurring legal expenses associated with efforts to collect Verizon pole attachment revenue. It is very important to note that the 2014 test year contains approximately $3.8 million of pole attachment revenues from Verizon that are currently being disputed. The requested revenue requirement is $3.8 million lower as a result. Customers are benefitting by the inclusion of this disputed revenue amount in the company's filing. It is only reasonable that the litigation costs to capture these revenues be recovered through proposed operating expense. Including the requested Verizon legal fees is both balanced and appropriate.

Tampa Electric witness S. Beth Young discusses this issue further in her rebuttal testimony.

OTHER POST-RETIREMENT EMPLOYEE BENEFITS

Q. Should an adjustment be made to rate base for unfunded

Other Post-Retirement Employee Benefits ("OPEB") liability and any associated expense?

A. No. The company has consistently recorded OPEB liability and expense over time. OPEB includes certain post-retirement health care and life insurance benefits. The accounting for OPEB incorporates the future defined benefit for both active employees as well as those already retired. The present value of future benefits are calculated and provided by Tampa Electric's actuaries. The company records expense while recognizing the recommended liability as a reserve. The company pays retiree medical claims as incurred and charges the reserve. The reserve amount serves to reduce working capital and therefore rate base in the company's proposed revenue requirement as filed.

Q. Would an adjustment be consistent with the Commission's previous decisions for Tampa Electric?

A. No. In Tampa Electric's last base rate proceeding (Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI), the Commission found that the company's OPEB balances and expenses were reasonable:

> We find that there is sufficient record evidence to

demonstrate that Tampa Electric's unfunded OPEB liability is reasonable and has been included in rate base. Thus, no adjustment to the company's rate base concerning unfunded OPEB liability is warranted. (Page 22) We find that TECO has presented sufficient information to demonstrate that its Other Post Employment Benefits Expense is reasonable. (Page 54)

STOCK COMPENSATION EXPENSE

Q. OPC's witness Schultz, III states on page 24 lines 13-17 that "I would then recommend that the $5,084,200 of expense for the Tampa Electric stock compensation be reduced by $1,881,154 so that only 63 percent is expensed. This would be consistent with the company's expense factor for pensions and other employee benefits." Do you agree with this treatment?

A. No. The company does not capitalize stock compensation expense. To use 63 percent would ignore the actual manner in which this expense is reflected in the cost profile of the company.

PARENT ALLOCATION

Q. HUA witness Kollen and OPC witness Ramas suggest the

test year expenses be reduced by $2.9 million to reflect the projected annual impact of the proposed TECO Energy acquisition of New Mexico Gas Company ("NMGC") that was provided by the company. Do you agree with this suggestion?

A. No. The acquisition of NMGC is still pending and uncertain. Therefore, it would not be appropriate for the company to make any adjustment to parent allocation due to the timing and uncertainty of this acquisition. The company's uncertainty of completing the NMGC acquisition is driven by the company's inability to guarantee the final outcome.

Q. OPC witness Ramas states on page 24, line 17, an additional $378,082 of allocated cost be removed to account for shifting of costs from other current subsidiaries of TECO Energy to Tampa Electric in the test year. Do you agree with this statement?

A. No. The parent company has consistently applied the current Modified Massachusetts Method to calculate the allocation of parent cost to its subsidiaries since 2002. TECO Energy is a publicly traded company that is subject to certain compliance costs. Many of these

costs are not dependent on the financial profiles or number of affiliates that are supported by these corporate level services. Therefore, future changes in the subsidiary earnings or asset profiles will not change the total allocable expenses projected at the parent company and thus should not result in any adjustment to Tampa Electric's portion of parent allocations.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. I have delineated the concerns and disagreements I have regarding the substance of the testimonies of witnesses Chriss, Gorman, Kollen, Schultz, Pous, Ramas, and Pollock. Their assertions contain a variety of points that are not accurate, not logical, not appropriate and/or not in agreement with the Commission's regulatory policies in a number of areas. I have presented facts and information that support the company's petition, the reasonableness and prudence of amounts and positions presented by Tampa Electric, and the appropriateness of the revenue requirement contained in the company's filing.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI
IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT
OF
WILLIAM R. ASHBURN

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

WILLIAM R. ASHBURN

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

A. My name is William R. Ashburn. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Director, Pricing and Financial Analysis for Tampa Electric Company ("Tampa Electric" or "company").

Q. Are you the same William R. Ashburn who filed direct testimony in this proceeding?

A. Yes, I am.

Q. Please state the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the prepared direct testimony of witnesses Stephen J. Baron, testifying on behalf of the WCF Hospital Utility Alliance ("HUA"), Jeffrey Pollock, testifying on behalf of the Florida Industrial Power Users Group ("FIPUG") and

William B. McNulty testifying on behalf of Commission Staff ("Staff"). Additionally, in conjunction with the rebuttal testimony being provided by Tampa Electric Witness Jeffrey S. Chronister, I will be addressing Office of Public Counsel ("OPC") witness Donna Ramas' jurisdictional separation issue regarding the updated information for transmission service commitments of the wholesale customers, Calpine and Auburndale Power Partners ("APP").

Q. Have you prepared an exhibit to support your rebuttal testimony?

A. Yes, I am sponsoring Exhibit No.__ (WRA-2), consisting of four documents, which were prepared under my direction and supervision. These consist of:

Document No. 1	Illustration of Economic Generation Selection and Allocated Cost Determination
Document No. 2	Comparison of Class Cost Results by Production Capacity Allocation Method
Document No. 3	Adjustment for Cost Effects of Updating Wholesale Transmission Service Requirements
Document No. 4	Minimum Distribution System Analysis

Q. Please summarize the key concerns and disagreements you have regarding the substance of witness Baron's, witness Pollock's, and witness McNulty's testimonies and the jurisdictional separation issue of witness Ramas.

A. My key concerns and disagreements are in regard to the following arguments raised by these witnesses as follows:

1. Witness Pollock's request to maintain IS as a separate rate class.
2. Witness Pollock's and witness Baron's criticisms of the company's proposed 12 CP & 50 Percent AD method and their recommendations to employ the 12 CP and 1/13th AD method.
3. Witness Pollock's and witness Baron's criticisms of the design of demand and energy charges in the GSD and GSDT rate schedules.
4. Witness McNulty's criticisms of the company's MDS determinations and the level of impact MDS has on the resultant cost classifications.
5. Although not necessarily in disagreement with witness Ramas, I wish to provide the adjusted rate base and net operating income cost elements resulting from the Jurisdictional Separation Study that has been adjusted to reflect updated information regarding the company's provision of

firm wholesale transmission service to Calpine and APP.

RETAINING IS AS A SEPARATE RATE SCHEDULE AND COST OF SERVICE CLASS

Q. Witness Pollock testifies that the IS rate schedule should be retained and that it should be retained as a separate class of service within the retail Class Cost of Service Study ("CCOSS"). Are his arguments persuasive and does he provide any new evidence to support this proposal?

A. No, as explained below, while he identifies some differing characteristics of the small group of customers comprising the IS class, his arguments for its retention have no merit and are not persuasive.

Q. Does witness Pollock agree that the feature of "interruptibility" in the IS rate schedules was removed in Tampa Electric's last rate case?

A. Yes. Witness Pollock made such a statement in his direct testimony on Page 10, line 22. Therein, he stated further that this action transformed the IS rate schedules from interruptible to a set of separate cost-

based firm service rate schedules.

Q. If "interruptibility" is no longer a feature of the base rate aspects of the IS rate schedules, as witness Pollock acknowledges, then what homogeneous features or characteristics exist among the remaining customers under the IS rate schedules that warrant IS being retained as a separate set of rate schedules and class within the CCOSS?

A. I do not believe there are any and witness Pollock presents none. Witness Pollock has presented data showing that the 43 remaining accounts taking service under the IS rate schedules have different "aggregate" load characteristics than the comparable "aggregate" load characteristics of accounts served under the GSD rate schedules, but not that those 43 accounts are homogeneous as a group. The remaining customers taking service under the IS rate schedules are rather diverse and are made up of schools, chemical plants, mining, manufacturing, and communications facilities. It is not surprising that any selection of 43 diverse customers from within the GSD rate class could pose aggregate characteristics different than that of the aggregate of the GSD class. Absent consideration of the "interruptibility" characteristic,

which witness Pollock agrees is no longer an aspect of service under IS, I don't think there is any common thread among the remaining IS customers that warrant them to be treated as a separate set of rate schedules or class within the CCOSS.

Q. Witness Pollock observes, from the results of the company's CCOSS, that the presently existing IS rate class is already above parity under its present rates. Do you concur?

A. Although I agree that the company's CCOSS shows this to be the case, I am concerned as to the forecast of coincident peak load responsibility for the IS class as it is embodied in the CCOSS. Since much of the IS class's allocated cost is based on coincident peak ("CP") load responsibility, any variation in its CP forecast has a significant result on its parity position. Of all the rate classes presented in the company's CCOS, the determination of the IS class's CP load is probably the most difficult to ascertain. This is because of three factors: (1) its relatively small size with respect to number of accounts that are members (i.e., 43) (2) in recent years the IS class has had the largest change in its load requirements of any of the company's rate

classes and (3) the IS class consists of a substantial amount of accounts taking service under a standby rate schedule, relative to the total membership, which usage can be very volatile as to its needs and deceiving when included in aggregate analysis.

Witness Pollock provided in his Direct Testimony data showing the IS class's CP load factor for the historic years' 2010, 2011, and 2012. He also showed the CP load factor that was embodied in the CCOSS. A summary of this data is shown below:

IS 12CP Load Factor

2010	2011	2012	2014 Test Year
94%	94%	95%	110%

As can be seen from this data, the 2014 Test Year's 12 CP load factor for IS does not appear to be in line with that experienced in recent historic years. If the 2014 Test Year's 12 CP load factor for IS was indeed over-forecasted, and if it were adjusted to a 12 CP load factor more in line with that which the class has historically experienced as shown above, the IS rate class would not have been shown to be above parity in the CCOSS I have presented.

Q. You mentioned the difficulties in forecasting CP loads for those standby rate customers that comprise a large portion of the IS class's requirements. Didn't the Commission's Standby Rate Order recognize the volatile usage of standby customers and require that standby rate charges be set on the basis of system costs?

A. Yes. In Order No. 17159 in Docket No. 850673-EU, the Commission recognized that serving standby load is a function of a customer's generation reliability, and that diversity exists among standby customers with respect to the times of their generator outages. For this reason, the Commission required that standby rate charges be developed on the basis of system coincident peak power supply unit costs, factored by a probability of occurrence of generation outage. The company has followed this prescription in the design of its proposed standby rate charges in this proceeding. As a result, standby load requirements should be recognized and treated apart from that of a class's full requirements for costing and pricing purposes.

Q. What is the billing effect of the company's proposed rate schedule SBF if it is applied to the existing IS standby customers?

A. The billing effect proposed by the company would reflect the elimination of the IS rate schedules, including SBI. The billing effect was previously shown in Document No. 3 of Exhibit No. ____ (WRA-1) of my Direct Testimony in this case. That document shows there to be six IS standby customers, numbers 38 through 43 on the document, which in aggregate make up approximately 25 percent of the IS class's total revenues. The billing comparison shows that each of these customers would actually realize a billing benefit under the company's rate proposal to transfer these SBI customers to service under SBF. I would expect these customers would want to support the company's proposal to eliminate the IS rate schedules.

Q. Witness Pollock criticizes Tampa Electric for having too few rate classes. Is his criticism warranted?

A. No. Tampa Electric is proud of its proposed rate classes and the rate structure they represent in that the company has reduced its number of rate classes over the years to four major rate classes: (1) Residential, (2) General Service Non-Demand, (3) General Service Demand, and (4) Lighting (for which the latter is considered two sub-groups: Lighting Energy and Lighting Facilities). The company has minimized the number of rate classes by

incorporating rider schedules, optional rates, and recognizing various combinations of metering and delivery voltage applications within its rate schedules. The company believes that its general service rate designs should attempt to recognize costs based on load factor and not business type or size. It appears that witness Pollock puts forth his criticism on the basis that eliminating the IS rate class results in one fewer rate class as compared to the other Florida investor-owned utilities ("IOU's"), highlighting for example (in a table on page 18 of his testimony) the large number of rate classes for Florida Power & Light ("FP&L"). Although FP&L has a large number of rate classes in their CCOSS, many are differentiated only by delivery voltage or size, which Tampa Electric has accomplished within the same rate class.

Importantly, FP&L does not reflect its curtailable customers (comparable to Tampa Electric's IS customers) under separate rate classes. FP&L does have individual rate schedules for its curtailable service customers, but they are not treated as separate rate classes. Instead their base rate charges are set at the same base rate charges as non-curtailable customers with credits provided to recognize their curtailable service

characteristic. This is the very approach being proposed by Tampa Electric in this case for the IS customers.

PRODUCTION COST ALLOCATION METHODOLOGY

Q. Witness Pollock and witness Baron have both raised a number of criticisms regarding the level of energy responsibility Tampa Electric proposes to include in the production capacity allocation methodology. Would you comment on their testimony?

A. Yes. These witnesses have raised a number of issues attempting to find fault with the 12 CP and 50 Percent AD methodology. However, I find that their testimony provides little, if any, support or persuasive rationale for the use of the 12 CP and 1/13th AD methodology which they are advocating to replace it with, other than that the 12 CP and 1/13th AD methodology has been the "traditional method" used by other utilities in Florida for many years.

Q. Do you think that serious class cost allocation inequities result from the use of the 12 CP and 1/13th AD production capacity cost allocation methodology which is being advocated by witness Pollock and witness Baron?

A. Yes. I believe that utilizing the 12CP and 1/13th AD method does result in an inequitable allocation of costs to the company's retail rate classes. The method over-allocates cost responsibility to those rate classes having proportionally more peak usage (e.g., the residential class) and under-allocates cost responsibility to those rate classes that are relatively less peak intensive with their usage (e.g., the general service demand class).

Q. Have you prepared an exhibit that illustrates the inequity that can result from the use of a production cost allocation methodology which relies predominantly on peak demand with little or no recognition of energy responsibility?

A. Yes. I have prepared a simple generation planning and cost allocation illustration which is presented in Document No. 1 of my exhibit and is entitled "Illustration of Economic Generation Selection and Allocated Cost Determination." The exercise focuses on selecting the most economic generating unit to serve a system comprised of two types of load, (1) Peak Load and (2) Off-Peak Load, and the cost allocations that are applied.

Q. Please explain the Document No. 1 in your Exhibit.

A. The planning exercise assumes a generation planner has available two types of generating units which can be installed to serve a hypothetical system electric load profile. For this purpose, I have selected the same two types of generating units (with their respective costs) that HUA witness Baron employed in his testimony regarding a screening exercise which he performed. One type of unit, identified as Type A on Page 1 of Document No. 1 of my exhibit, is an advanced combustion turbine unit which has a relatively low fixed cost but a relatively high operating cost. The second type of unit, identified as Type B, is a conventional combined cycle generation plant which has a higher fixed cost but a lower operating cost. For simplicity, I have assumed that both types of generating units have 100 percent availability, thereby eliminating the need in this exercise to consider reserves. On Page 1 of Document No. 1 of my exhibit, the annual costs (i.e., both fixed and variable costs) are shown for each type of unit, and their respective total annual costs are shown in graphical form as a function of capacity factor. The graph shows that the Type A unit has the lowest total annual cost of operation when utilized at less than a

26.9 percent capacity factor, and the Type B unit has the lowest total cost of operation when utilized at a capacity factor greater than 26.9 percent. This represents the "breakeven point" upon which witness Baron (and also witness Pollock, with different input values) places such reliance.

Q. Please continue to the second page of your Document No. 1 of your exhibit.

A. On Page 2 of Document No. 1 of my exhibit, two electric system annual load requirements are presented as case studies. The system load requirements are presented in the form of an annual load duration curve ("ALDC"). An ALDC is used in power system planning studies as an aide for analyzing load data. It differs from a chronological hourly load profile in that an ALDC plots the system's hourly loads in a descending order of magnitude, ignoring the clock time they occurred during the year.

In the first case study, Case No. 1, the ALDC depicts a system peak load of 500 MW with an annual load duration occurring for 10 percent of the hours in the year. All the hourly loads are of the same peak magnitude and there are no lesser hourly loads or off-peak load requirements.

In other words, Case No. 1 is intended to depict an electric system comprised of only peak load hours occurring for 10 percent of the hours in the year.

In the second case study, Case No. 2, the ALDC depicts an electric system comprised of the same peak hourly loads of 500 MW during 10 percent of the hours, but it depicts the potential of serving off-peak load for the remaining 90 percent of the hours in the year. This potential for off-peak hourly loads is shown as the dashed line of the ALDC, and the area under the dashed line is the energy usage of the potential off-peak load.

The purpose of these two hypothetical cases is to present two different electric system loads: one system comprised solely of "Peak Load" requirements and the other system comprised of both "Peak Load" and "Off-Peak Load" requirements. The task of the generation planner is to select the Type A or Type B generating unit as the most economical to supply the load requirements of each. After the appropriate generating unit selection is made, a cost allocation analysis is performed on Page 3 of Document No. 1 my exhibit using the Peak Production Capacity Allocation Method ("Peak Method") to determine the allocated costs that would result under each case for

serving the Peak Load and Off-Peak loads.

Q. What process would the planner use to make the most economic selection?

A. The planner would rely on the economic analysis performed on Page 1 of Document No. 1 of my exhibit. For the system electric load of Case No. 1 comprised solely of "Peak Load", a generating unit operating at a 10 percent capacity factor would be required. Since this capacity factor is less than the 26.9 percent capacity factor calculated on Page 1, the planner would choose generating unit Type A. For the system load of Case No. 2, a load comprised of both "Peak Load" and potential "Off-Peak Load", a generating unit operating at 100 percent capacity factor would be required. Since this capacity factor is greater than the 26.9 percent capacity factor calculated on Page 1, the planner would choose generating unit Type B.

Q. Using the Peak Method, would you summarize the results of the costing analyses that were performed for each of the two system load cases?

A. Yes. The resultant cost analyses are summarized below:

Case No. 1

System Load: 500 MW Peak Load

Generating Unit Selection: Type A

Allocation Method: Peak Method

		Rate Class	
	System	Peak	Off-Peak
Resultant Total Cost	$167.20	$167.20	N/A

Case No. 2

System Load: 500 MW Peak Load and Potential Off-Peak Load

Generating Unit Selection: Type B

Allocation Method: Peak Method

		Rate Class	
	System	Peak	Off-Peak
Resultant Total Cost	$63.63	$200.65	$48.40

Q. What are your observations as to the results of this cost allocation exercise that uses the Peak Method?

A. I believe this exercise provides a number of noteworthy observations or consequences. First, it makes the point that it is the anticipation of "Off-Peak Load" that supports the economic justification for the selection of the more capital intensive, yet more efficient Type B generating unit in Case No. 2. The overall system cost

of electricity is reduced from a system cost of $167.20 per MWH by the selection of Type A generating unit in Case No. 1 to a system cost of $63.63 per MWH by the selection of Type B generating unit in Case No. 2. Second, however, by the selection of Type B generating unit in Case No. 2, the total cost of service allocated to serve the "Peak Load" using the Peak Method has increased from $167.20 per MWH to $200.65 per MWH - an amount significantly more than the cost of serving the "Peak Load" on a stand-alone basis as depicted in Case No. 1. Lastly, under the Peak Method, the "Off-Peak Load" does not get allocated any fixed capacity cost and gets the advantage of being assigned only the cost of Type B's more efficient operating cost of $48.40 per MWH.

Q. What conclusions are illustrated regarding the use of the Peak Method in this simple planning exercise?

A. I find and conclude from this exercise that the use of the Peak Method poses, in particular, two disconcerting outcomes that result in cost allocation inequities for a system comprised of rate classes having both "Peak Load" and "Off-Peak Load". First, I find it to certainly be an inequitable outcome that the "Peak Load" is allocated a greater amount of cost than that required to serve this

load on a stand-alone basis. The addition of "Off-Peak" load to a system should rightfully result in lower system costs per MWH, as it did in Case No. 2, and this should afford some shared cost advantage, or at least pose no harm, to the "Peak Load". Second, I find it an inequitable outcome that the use of the Peak Method results in no fixed cost allocation to the "Off-Peak Load", while such load enjoys the benefits of the system's low operating costs. It is simply a matter of equity that the "Off-Peak Load" provide some contribution to the system's fixed costs, especially if the system is producing energy at lower operating costs by the selection of a more capital intensive unit as was selected in Case No. 2 of the planning exercise.

Q. Does a production cost allocation method like the one that the company proposes, one that includes a significant weighting of energy responsibility, help alleviate the inequities that you find by use of the Peak Method?

A. Yes, I think a significant consideration of energy responsibility accomplishes that. To demonstrate this, I have employed a method like that which Tampa Electric is proposing in this proceeding to the same system costs as

presented in Case No. 2. This cost allocation is shown as Case No. 3 on page 4 of Document No. 1 of my exhibit which incorporates a capacity allocation weighting of peak load responsibility by 50 percent and energy (or average demand) responsibility by 50 percent (for purposes of this example, I will call this the Peak and 50 Percent AD Method).

Q. Would you compare the allocation results of employing the Peak and 50 Percent AD Method with that of the Peak Method for your planning and costing exercise?

A. Certainly. A summary of the comparative findings is shown below:

Case No. 1

System Load: 500 MW Peak Load

Generating Unit Selection: Type A

Allocation Method: Peak Method

		Rate Class	
	System	Peak	Off-Peak
Resultant Total Cost	$167.20	$167.20	N/A

Case No. 2

System Load: 500 MW Peak Load and Potential Off-Peak Load

Generating Unit Selection: Type B

Allocation Method: Peak Method

		Rate Class	
	System	Peak	Off-Peak
Resultant Total Cost	$63.63	$200.65	$48.40

Case No. 3

System Load: 500 MW Peak Load and Potential Off-Peak Load

Generating Unit Selection: Type B

Allocation Method: Peak and 50 Percent AD Method

		Rate Class	
	System	Peak	Off-Peak
Resultant Total Cost	$63.63	$132.14	$56.01

Q. Do the results of applying the Peak and 50 Percent AD Method in your planning and costing exercise alleviate the cost allocation inequities that you described were inherent in the Peak Method?

A. Yes. By employing the Peak and 50 Percent AD Method in Case No. 3 of this exercise, the costs for the "Peak Load" and "Off-Peak Load" groups are allocated amounts that I find more reasonable and which do alleviate the inequitable concerns that I had observed in the use of the peak method. First, the "Peak Load" group's

resultant allocated cost of $132.14 per MWH is a lesser amount than its stand-alone cost of $167.20 per MWH, whereby such allocated cost was greater using the peak allocation method. And, secondly, this allocation method results in the "Off-Peak Load" being assessed an amount of $56.01 per MWH – an amount of $7.71 per MWH above the system's operating cost of $48.40 per MWH. I consider this to be a fair and reasonable contribution for the "Off-Peak Load" to make toward the system's fixed cost since they are receiving the benefits of the system's low operating cost.

Q. What can one conclude from your illustrative Exhibit?

A. Although my Exhibit is a simple illustration of a generation planning exercise and cost determination for serving two types of loads, i.e. "Peak" and "Off-Peak", I believe the results are meaningful and provide an inference to the impact of cost allocation on the rate classes in this proceeding. It is my conclusion that the exercise meaningfully demonstrates that a rather significant energy weighting for production capacity cost responsibility is warranted to alleviate inequities in the use of a predominately peak allocation method.

Q. Would witness Pollock and witness Baron concur with your simple generation planning analysis and the concept you have described of selecting the most economic resource?

A. Yes, I believe they would and I believe they do express agreement in their testimony with that aspect of my exercise. Witness Pollock makes the same type of point of economic selection by using rental cars as an illustration and witness Baron presents his screening selection analysis. We all seem to concur with the concept that the economic selection of a facility should be based on a consideration of total costs, both fixed and variable. I believe we are in agreement that the economic principle of capital substitution is exercised in the selection of the most economic facilities. We also concur that there is an economic break-even point for which one type of facility becomes more economic than the other.

Q. Then, what is the primary difference between you and witnesses' Pollock and Baron that gives rise to the argument over what is the most appropriate production cost allocation methodology that should be employed?

A. In spite of our common understandings, there is a major

costing philosophy difference being posed by these witnesses that I strongly disagree with in the context of the Commission's rate-making practices and policies. What the Commission decides as the appropriate costing philosophy should dictate whether the predominately peak or heavily weighted energy methodology should be employed.

The costing philosophy difference relates to the discussion by witnesses Baron and Pollock as to their treatment for costing usage before and after the economic break-even point of generation selection. Both of them assert that energy usage beyond that of a break-even required amount of usage does not impose any additional capital costs on the system and therefore should not be assessed any cost responsibility.

Although their assertion may be mathematically correct, the assignment of all premium or capital substitution costs to usage less than that of a break-even point, and the corresponding lack of any assignment of costs to usage greater than the break-even point, is certainly not an equitable or realistic principle. It is only proper and good cost allocation and ratemaking to employ methods which attempt to match costs with benefits. Whether it is

the first kWh used or the last, each kWh consumed (not just the ones prior to the break-even point) is a beneficiary of the system's lower operating cost that result from investment in these more efficient generating plants and should share equally in the cost of the premium or capital substitution investment that afforded the benefit.

Q. Do you have a simple example to demonstrate why it is more equitable that all energy use, not just the energy required for breakeven consideration, should bear capital substitution costs?

A. Yes. Consider the decision by a consumer to purchase a new high efficiency home air conditioning system for $2,000. Assume that this high efficiency system will have a 10-year life and it will result in $500 per year lower electric energy usage. Therefore, the purchase results in anticipated savings in electric energy usage of $5,000 over the life of the system. This is a good economic purchase because the $5,000 savings less the $2,000 cost produces a net benefit of $3,000. Using witness Pollock's and witness Baron's approach, they would take the $2,000 investment cost and divide it by the $500 annual savings to calculate the breakeven point

of four years. They would then claim that during the first four years, the customer would realize no net savings; however, there would be $500 per year net savings in the six remaining years.

I do not believe witness Pollock's and witness Baron's approach represents an equitable or even realistic viewpoint. It does not recognize the Commission's ratemaking practice of matching costs with benefits. In this example, the $2,000 cost should correspond to the full usage period that savings are realized which is all 10 years, not just the first four years. This use of the full usage period results in an allocated cost of $200 per year compared to the annual energy usage savings of $500 for an annual net savings of $300 for each year of its 10-year life. This is the most equitable treatment of matching costs and savings.

The flaw in witness Pollock's and witness Baron's breakeven analysis can be demonstrated in another way using this same air conditioning system example. If the purchaser of the more efficient system were to sell his home after four years, he would expect a greater sales price for the home by virtue of having the more efficient air conditioning system as compared to a home without

such a system. Likewise, a purchaser should be willing to pay more for this home with the expectation of lower electric energy costs. Under their concept, the seller should not expect to increase the value of his home because he would conclude that he has fully recovered the additional cost. However, the purchaser, without paying a premium for the house, would realize all the remaining electric energy savings. Costs and benefits are not matched. If a ratepayer were the seller in this case, he would not opt to adopt witness Pollock's and witness Baron's perspective.

Q. Witness Pollock and witness Baron both compare similarities of generation mix and planning by Tampa Electric to that of FP&L in support of the use of the 12 CP and 1/13th AD method which has been employed by FP&L. Do you think their comparisons are appropriate?

A. No. Since witness Pollock and witness Baron seemingly are using this comparison as primary support for their endorsement of the 12 CP and 1/13th AD for Tampa Electric in this proceeding, I will proffer a few observations regarding this method and its prior application to FP&L.

First, I recall that the Commission deviated from the 12

CP and 1/13th AD method for FP&L and applied a 100 Percent energy allocation to the fixed capacity costs associated with the initiation of operations of FP&L's nuclear units. Both witness Baron and witness Pollock fail to bring that fact into their praise of the purity of the 12 CP and 1/13th AD methodology in FP&L's case.

Second, I am not aware, other than in the proceeding described above, that the incorporation of energy weighting in the production cost allocation methodology was ever presented as an issue for discussion or consideration by the Commission for FP&L.

Q. Witness Pollock asserts that Tampa Electric's proposal to change its cost methodology in this proceeding is particularly dramatic and causes undue instability in both class revenue requirements and rate design. Do you agree?

A. No, although the company does believe a much greater weighting of energy responsibility in its cost allocation methodology is more appropriate today, I believe that witness Pollock has exaggerated the effect of this change, especially for the GSD/IS rate class that he represents. To make this point, I have prepared Document

No. 2 of my exhibit which compares the rate classes' allocated costs under various cost allocation methods. This exhibit shows that the allocated cost effect of the company's proposed change from the prior 25 percent energy weighting to the 50 percent energy weighting has the effect of only a 2.4 percent non-fuel cost increase on the GSD/IS rate class. I don't consider that to be such a "dramatic" effect in a rate increase proceeding that would cause undue rate instability for the customers that he represents.

Q. Witness Pollock and witness Baron in their testimonies recommended that the Commission reject the 12 CP and 50 Percent methodology as outcome oriented rather than cost-based. Witness Pollock in his testimony stated that the Commission's long-standing policy was to employ "cost-based pricing" rather than "price-based costing", and witness Baron in his testimony said that deciding to switch cost responsibility (i.e., increasing the energy allocation of production capacity costs) without a substantive link to cost causation was not good ratemaking policy. Would you agree with those views?

A. I can agree with the sentiment, but would remind them of the history in Florida regarding this element of cost

allocation for production cost allocation. Beginning as far back as the early 1980's the Commission has wrestled with the issue of how much of production capacity cost should be allocated on an energy basis as opposed to a demand basis. I discussed this in my direct testimony on page 31. This debate has been as much a cost causation debate as it has been an outcome and equity debate. Initially it was driven by concern about how much production capacity cost should be allocated to interruptible customers, because the value of the interruptible service was derived at that time through cost allocation within the CCOSS and not by credits applied to standard firm service rates. Production demand cost was not allocated to the interruptible class of service (under the cost causation theory that their load was not included in the determination of need for production plant) however cost allocation experts and the Commission at the time believed that some cost recovery of their production demand costs should be recovered through interruptible rates to recognize those customer's use of the fleet of generation built to serve their energy needs at times when they were not interrupted for firm customer capacity needs. As a result of this debate, the $1/13^{th}$ proportion of energy was determined an appropriate amount, based on the outcome being deemed

reasonable at that time, and applied across all the utilities in Florida.

Since that time, the interruptible nature of service to these customers has been converted from a base rate delivery to a credit applied to the base rates and recovered under the conservation clause. Now the energy proportion of allocation of production demand costs has become a debate over matters such as witnesses Baron, Pollock and I have been discussing - proper recognition of investment in production plant and the benefits of such investment associated with the fuel benefits that accrue from such investment being applied to all customers. The Commission wrestled with this issue in the last Tampa Electric base rate proceeding and resolved that a change from the $1/13^{th}$ (roughly 8 percent) energy proportion to a 25 percent energy proportion was justified and reasonable. In part the Commission made that decision based on cost causation and in part on outcome. Tampa Electric in this case has proposed to increase that proportion to 50 percent while witness Baron and witness Pollock oppose it in their testimony entirely on the basis of cost causation, and undoubtedly because the outcome of its acceptance by the Commission would result in an outcome detrimental to their client's

bills. I would suggest that this issue has always been, and will continue to be resolved by the Commission on both bases - cost causation support and the outcome of the choice made.

GSD RATE DESIGN

Q. Witness Pollock and witness Baron have criticized the company's method of revising the demand and energy charges of its demand measured general service rate schedules by not establishing these charges from the cost of service unit cost results. Do you believe this criticism is warranted?

A. No. Witness Pollock and witness Baron's premise is that all functionally related and classified capacity costs (i.e. production capacity, transmission capacity, distribution primary capacity, and distribution secondary capacity) should be recovered in a demand charge in those general service rate schedules where a billing demand is measured and a separate demand charge is applied. Likewise, they opine that only those functionally related and classified energy costs should be recovered in an energy charge of those rate schedules.

Although this may sound like a logical approach to rate

design, it is important to recognize that the demand that is measured for billing purposes is that of the customer's maximum 30-minute kW demand occurring during the billing period. Only one of the identified functionally related and classified capacity costs – that of distribution secondary capacity – is directly related to and bears direct cost responsibility for this particular demand measurement. And, as it turns out, the distribution secondary capacity costs are the least costly of these types of functional capacity costs to be recovered.

The cost causation and appropriate measurement for assessing cost responsibility for the other, relatively more costly functionally related and classified capacity costs are summarized as follows:

Cost Function	**Cost Responsibility**
50% Prod. Capacity - Demand	12 CP
50% Prod. Capacity - Energy	Energy Usage
Trans. Capacity	12 CP
Distribution Primary	NCP

Because of metering and billing constraints, measurement of a customer's demand at the time of the monthly system

peaks or at time of its respective class peak is generally not feasible. Under the Commission's prescribed general service rate design, these functional costs are simply apportioned and recovered under some combination of an energy charge and a billing demand charge. Based on load research performed by the company a number of years ago for the general service demand rate class, it was found that there was as good or even better correlation of a customer's coincident demand with a customer's energy usage than with that of a customer's billing demand. Thus, the company does not believe that recovering all functionally related and classified capacity costs on the basis of a customer's billing demand is the most appropriate rate design. The company believes its proposed levels of demand and energy charges fairly recover costs from customers over a wide range of customer load factors. Witness Pollock's and witness Baron's rate design proposal simply is one that favors high load factor customers and does not necessarily recognize the coincident load characteristics of customers by load factor when such costs are simply recovered on the basis of a customer's maximum or billing demand.

Q. Witness Pollock and witness Baron have criticized the

resulting large percent increase in the GSD's time of use ("TOU") rate schedule energy charge. In fact, witness Pollock describes the increase as "rate shock"? Do you disagree with his description of the impact of this charge?

A. Yes, I disagree. It appears that witness Pollock and witness Baron are not aware that the Commission prescribed a specific calculation for Tampa Electric to develop the energy charges for its Time of Use ("TOU") rate schedules. This was specified in Order No. 15451 of Docket No. 850050-EI. The company has followed the prescribed method in all of its rate cases since this rate order, including the present proceeding. The Commission intended that such rate design would result in relationships of on-peak and off-peak charges of a multiple ratio, which is a point of criticism by witness Baron and witness Pollock.

More importantly, however, I would have thought they would understand that the rate increase effect of the changes to the TOU energy charges should be viewed on a weighted or effective basis resulting from a customer's proportion of on-peak and off-peak usage – not from the on-peak or off-peak energy charge alone. The table below

shows the present and proposed GSD standard and GSDT energy charges and the effective TOU energy charges when weighted by the class's on-peak and off-peak proportions.

GSD/GSDT

Base Energy Rates	Current $/MWh	Proposed $/MWh	% Change
Standard	15.83	18.29	15.54 %
TOU			
On-peak	28.98	39.99	37.99 %
Off-peak	10.46	9.60	(8.22)%
Effective TOU:			
On-peak	8.40 (29% x 28.98)	11.44 (28.6% x39.99)	
Off-peak	7.43 (71% x 10.46)	6.85 (71.4% x9.60)	
Weighted	15.83	18.29	15.54 %

The TOU rate offering is predicated on a revenue neutral rate design, whereby if the customer had the same proportion of energy usage during on-peak hours and off-peak hours as compared to that experienced by the rate class as a whole, the effective TOU energy charge would be the same as the standard rate energy charge. The prior directive of the Commission required the off-peak energy charge to be set at the unit cost for the energy function in the company's cost of service study. The on-peak charge would then be mathematically calculated such

that the effective charge resulted in the standard rate energy charge.

It should be noted that a customer would not incur any greater effective energy charge than that shown for the standard rate. This is because only customers having lesser on-peak percent usage than the class's on-peak percentage would find TOU rates more beneficial and realize an effective lower energy charge. If a customer's on-peak percentage exceeded that of the class's, he would find the standard rate more economical.

Thus, the company's changes to its GSDT TOU energy charges would not create a "rate shock" impact for any GSDT customer as witness Pollock has described. When a GSDT customer maintains or improves his proportional energy usage, he will not realize any greater increase than that of the standard energy charge increase and may see even a lesser increase.

Q. Witness Pollock proposed an additional credit amount of $0.53 per kW over and above the company's proposed sub-transmission delivery voltage credit for the purpose of off-setting the increase that IS sub-transmission customers would incur in the event that the present IS

rate schedules are eliminated. What is your reaction to witness Pollock's proposal?

A. I find such a proposal to be arbitrary, unsupported, discriminatory, self-serving, and certainly not a demonstration of good ratemaking practices as he professes to endorse. I would note that this proposal would subsidize only the subtransmission-served IS customers transferred, and provide no such subsidy to the primary-served customers. Such a proposal, which appears entirely outcome-based and with no cost causation support as he has previously indicated in his testimony was a critical element in rate design, is poor ratemaking policy and should be rejected without any consideration.

MINIMUM DISTRIBUTION SYSTEM METHODOLOGY (DSM) AND RATIONALE

Q. Can you summarize your areas of agreement or disagreement with Staff witness McNulty regarding Tampa Electric's employment of the Minimum Distribution System ("MDS") concept in its proposed allocated class cost of service study and the resulting impact on proposed rate design?

A. Yes. I generally agree with witness McNulty's testimony which discusses the pros and cons of implementing the MDS concept, with some reservations which I will discuss. In

addition, I agree with certain aspects of his testimony where he proposes some improvement upon the company's proposed cost classifications, but disagree with certain other aspects of his findings. Witness McNulty appears to have the expectation that the MDS calculations should be a more precise determination than cost of service analysis can provide. Finally, I find his assessment of the positive and negative consequences of MDS to be rather over-stated as to their significance.

Q. Witness McNulty seems to suggest in the summary of his testimony that "doubt as to the extent there are misclassifications of distribution costs under traditional treatment" may be a basis for the Commission to not employ the MDS concept in cost of service studies. Do you agree with this assessment?

A. No. Witness McNulty appears to raise this "doubt" as a position that the Commission may rely on regarding whether to use MDS in this proceeding. Although he provides findings and support in his testimony that distribution costs do have at least a portion of costs that are customer-related as opposed to capacity-related, he states that the data is not available to make precise determinations of the extent of the misclassification.

"Precision" has never been a governing requirement with regard to adoption of a cost allocation or cost classification option being considered. For example, using coincident peaks to allocate power supply costs for future test periods or even historical test periods assures that accuracy in numbers is maintained, but the precision of using 12 coincident peaks versus 8, or summer/winter average, is not.

Q. Do you agree with witness McNulty that the company's determination of the classifications of distribution costs between customer and capacity is not a "precise" calculation?

A. Yes, most certainly. A great deal of costing work represents a best determination based on special analysis, judgment, data availability, costing theories, etc. There are few aspects of costing work, at least with regard to determination of proper classification of cost, that result in a precise calculation. I readily concede that the company's proposed MDS determinations in this proceeding are not a precise calculation. For example, the company purposely rounded its classification results to whole percentage points as opposed to setting forth the results out to a number of decimal places

(i.e., 64 percent poles, 24 percent transformers, 9 percent conductors). The lack of precise information in cost work should not be a deterrent to the development of a concept that one believes is more appropriate.

Q. Did witness McNulty's testimony seem to find favor or disfavor with regard to the company's MDS calculations?

A. I think witness McNulty favored the company's use of the zero-intercept method, which it used for application to conductors and transformers. He seemed to credit the company for resolving data problems by using replacement cost data rather than embedded data, although he stated this was contrary to the NARUC cost manual. He expressed particular criticism on two aspects of the company's calculations: (1) the recognition of too few observations in its regression model for conductors; and (2) the use of the minimum size method for poles in lieu of the zero-intercept method.

Q. Have you evaluated witness McNulty's criticism for using too few observations in the regression model for conductors?

A. Yes. The company originally employed three observations

that represented the predominant types and quantities of conductors used by the company for primary distribution purposes. I agree with witness McNulty's Exhibit No. ___ (WBM-4) that shows the use of only these three observations result in a rather wide band of statistical confidence. As a result, the company has added one more observation as the only additional observation of primary conductors in use today by the company. The result of the revised regression analysis employing four observations points is shown on page 1 of Document No. 4 of my exhibit. This document shows a resultant zero-intercept value of $0.45 per conductor foot with a significantly improved band of confidence. As shown on page 2 of Document No. 4 of my exhibit, the use of this revised zero-intercept value does not change the resultant customer classification of 9 percent for conductors that was derived previously by the company.

Q. What is your response to witness McNulty's second criticism, about the company's use of the minimum size system method rather than the zero-intercept method for determining the classifications for poles?

A. First, I believe the minimum size method is the only feasible method for applying MDS to poles. Poles are

comparatively unique facilities compared to the other electrical facilities that MDS is applied. Pole cost is not as easily measured in terms of electrical capacity as is the case for conductors (wire size) or transformers (KVA size). The NARUC manual describes using height and class as the variable measure of pole cost. Height and class selection of poles are not just a function of load carrying capability, but a selection based on a number of additional considerations: construction standards (e.g. wind loading); safety codes (e.g., overhead clearances); the type of electrical equipment and the number of joint-user attachments installed on the pole; and locational requirements or restrictions.

Where pole size (height) is used as the variable function, the company finds rather unrealistic results are produced for the zero-intercept determination. This is shown on page 4 of my Document No. 4 of my exhibit where I used the same data values as witness McNulty did in his Illustration B of Exhibit No. WBM-3. My calculation shows an amount of -$190 as the zero-intercept value of pole cost, which obviously is not a realistic result. It should be noted that I do not agree with the mathematical presentation that witness McNulty employed in his zero-intercept calculation of data for

poles since he did not properly recognize the variable x value as the actual pole size (height), but simply assigned equally spaced numbering to the data as the x value.

Secondly, I take issue with witness McNulty's concern that the company's use of its selected 30 ft. pole as the minimum size pole overstates the customer component classification of pole costs. The company does not consider 30 foot poles as having much capability in this regard. The company utilizes 30 foot poles only in situations requiring minimal electrical loads, such as for supporting a street light fixture or a secondary wire from a transformation, or a service cable. Where electrical load becomes a consideration, the company generally utilizes a 40 foot or higher pole.

Q. Are there any findings by witness McNulty that you believe should be cause for Tampa Electric to change its MDS determinations in this proceeding?

A. No, other than the revision to the number of observations for conductor sizes that I discussed previously that had no impact on the final results. Although this was Tampa Electric's first attempt to develop MDS classifications,

the company does expect to make refinements and attempt to improve upon these calculations in the future. However, the current development has resulted in reasonable and appropriate application for use in this proceeding.

Q. Witness McNulty cites the revenue and bill impacts of Tampa Electric's implementation of MDS on its customers in his Exhibit No. WBM-5. Do you agree with the information presented in this Exhibit?

A. With the exception of the LS or Lighting Services' classes, I agree with the impacts of MDS on customers that witness McNulty shows in this Exhibit. With respect to the LS classes, I think that witness McNulty misinterpreted the number of "217" for lighting service customers in calculating his impact of MDS on lighting service customers. The impact should instead be shown on the basis of serving a total of 206,663 lighting fixtures. The number of "217" lighting customers that appears in the company's statistics represents those accounts that have only lighting services billed under that account. This measurement doesn't recognize the number of lighting fixtures for these accounts nor the number of fixtures being served under those other

accounts having multiple services being billed. The more appropriate and meaningful impact for the LS class should be shown as follows:

Revenue Requirements MDS $(000)	Revenue Requirements DOCC $(000)	Revenue Requirements MDS-DOCC $(000)	Number of customers	Average Annual Bill Impact	Average Monthly Bill Impact
39,668	40,296	(628)	206,663	(43.03)	($0.25)

Q. Witness McNulty comments on some of the consequences that might result from ratemaking that recognizes the MDS concept in a utility's costing and pricing. Do you agree with his comments?

A. Yes, but to a lesser extent. Foremost, the company is proposing applying the results of implementing the MDS concept in the design of its rate structure because it believes this method represents the most equitable costing and pricing treatment to be afforded customers for the recovery of the company's distribution costs. In addition, I do agree with witness McNulty that MDS may pose certain price elasticity and revenue stability impacts as well. However, I think such additional effects are likely to be rather minimal and not have the significance of effect he implies.

For example, witness McNulty indicates that rates based on MDS would have lower energy charges and thus pose less of a price signal to customers thereby resulting in a disincentive for customers to pursue energy conservation. The lower energy charge resulting from MDS for a residential customer is a lesser amount of 0.36 cents per kWh (reflected in the company's proposed rate design) as compared to the full energy charge of about 10 cents per kWh. This amounts to about a 4 percent price impact, and it is questionable that this magnitude of difference would meaningfully affect a residential customer's consumption behavior.

Another example cited by witness McNulty as a result of the consequence of MDS is that rates based on MDS may provide utilities a more certain and steady stream of revenue by the application of higher customer charges and lower demand and energy charges. In the rate designs proposed to recover the company's proposed revenues in this proceeding, as a result of MDS an additional amount of about $49 million of base revenue has been designed to be recovered on the basis of customer charges rather than usage charges. The company's total proposed base revenue in the proceeding is over $1 billion. Thus, MDS results in less than 5 percent of the company's base revenues

being recovered on a less risky or steadier basis than otherwise.

UPDATE OF WHOLESALE TRANSMISSION AGREEMENTS

Q. OPC witness Ramas discusses the adjustment made by Tampa Electric to remove any cost treatment in the jurisdictional separation study related to the provision of firm transmission service for the wholesale customers' Auburndale Power Partners ("APP") and Calpine. Does the company have an update as to the status of the needs of these wholesale customers?

A. Yes. Subsequent to the company's filing in this proceeding, Calpine made a commitment to extend a portion of its firm transmission service agreement under Tampa Electric's wholesale open access transmission tariff that reduces their commitment from 526 MW to 249 MW effective after May 31, 2014. As of the filing of this rebuttal testimony, APP has not made a commitment for transmission service in the future and there is no current expectation that APP will make any commitment for transmission service in the foreseeable future. As a result of this updated information, witness Ramas believes the company's Jurisdictional Separation Study should be updated to reflect this more current information for the 2014 test

year.

The company agrees with witness Ramas's general discussion to reflect the effect of the updated Calpine transmission load requirement in its Jurisdictional Separation Study. In an effort to make it clear as to the effect of including the Calpine transmission service requirement in its Jurisdictional Separation Study, Document No. 3 of my exhibit delineates Calpine's updated cost effect on each component of rate base and net operating income in the Jurisdictional Separation Study. The effects shown on this document were determined by comparing the company's original filed Jurisdictional Separation Study with that of a revised Jurisdictional Separation Study that incorporates a wholesale transmission load responsibility of 249 MW for Calpine in all months of the test period. As witness Jeffrey S. Chronister has recommended, any revenues the company receives in the test period for firm transmission service in excess of that recognized in the Jurisdictional Separation Study would be credited to the fuel clause and spread over a 12 month period. This would apply to the excess (526 MW less 249 MW) of service revenues from Calpine occurring for the first five months of the test year.

With regard to APP, as indicated earlier there is no current expectation that APP will be seeking to roll over their current transmission contract. Therefore, no adjustment is being made to the proposed jurisdictional separation.

The effect of including the Calpine transmission load in the Jurisdictional Separation Study, of course, increases the wholesale jurisdictional cost and reduces the retail jurisdictional cost. It should follow that any revenues associated with this cost allocation to the wholesale jurisdiction is directly attributable and assignable to the wholesale jurisdiction. Witness Ramas, in her testimony, appears to have confused this point in the calculation of her proposed adjustment related to this jurisdictional separation issue and erroneously assigned the Calpine transmission service revenues to the retail jurisdiction.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addresses the intervener witnesses' Pollock and Baron's position on the issues as follows:

1. Retaining IS as a Separate Rate Schedule and Cost of Service Class

Witness Pollock has not provided any good argument for sustaining the present IS customers as a separate rate class for base rate costing and rate design purposes. He concedes that, as a result of Tampa Electric's last rate proceeding, "interruptibility" is no longer a feature of the base rate aspects of the IS rate schedules. I urge the Commission to bring final closure to the IS rate schedules which are no longer necessary since interruptible service is otherwise available as an option under the company's GSD rates schedules. There are no remaining reasons for this select group to receive rate class or schedule treatment different than other customers electing to be served on an interruptible basis.

2. Production Cost Allocation Methodology

Neither witness Baron, nor witness Pollock provide any support for their recommended use of the 12 CP and $1/13^{th}$ AD method other than its use by the other Florida utilities. I demonstrate the inequity that results from the use of this predominately peak allocation method which is alleviated by the use of the company's proposed 12 CP and 50 Percent AD method that more

substantially recognizes energy responsibility and provides a better match of costs and benefits.

3. GSD Rate Design

Both witness Baron and witness Pollock have misconstrued the cost causation of much of the company's capacity costs by claiming that all capacity related costs (i.e. production capacity, transmission, capacity, distribution primary capacity, and distribution secondary capacity) should be recovered on a billing kW demand basis and none of these costs on an energy basis. The company's GSD rate design fairly recognizes recovery of these costs on both a billing demand charge and an energy charge basis and I find that their assertions are not supported by load research correlations or any cost determinations by load factor.

Both witness Baron's and witness Pollock's criticisms of the company's calculation of TOU energy charges appear to result from a misunderstanding of the Commission's directive for designing TOU energy charges. The design is intended to create a multiple ratio, which witness Pollock specifically criticizes, between on-peak and off-peak energy charges in order to

provide customers incentive to shift usage. Additionally, the company's proposed TOU energy charges do not pose a "rate shock" to TOU customers (as alleged by witness Pollock) in that the customer's energy charge is effectively a weighting of the on-peak and off-peak energy charges which is not likely to exceed the increase proposed for the energy charge of the standard rate.

The proposal by witness Pollock to arbitrarily increase the sub-transmission delivery credit, in order to mitigate certain customer's rate increase in this proceeding, should be rejected without consideration.

4. Minimum Distribution System (MDS) Methodology and Rationale

I am in general agreement with witness McNulty's testimony on MDS and his recognition that traditional distribution treatment has misclassified certain distribution costs. I do not believe his criticisms of the company's MDS determinations are warranted nor do they have an impact on the resultant cost classifications it has employed in adopting the MDS concept.

5. Update of Wholesale Transmission Agreements

The company agrees with OPC witness Ramas to recognize the most current information regarding wholesale transmission service in its Jurisdictional Separation Study.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT

OF

WILLIAM R. ASHBURN

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2	Comparison of Class Cost Results by Production Capacity Allocation Method	62
3	Adjustment for Cost Effects of Updating Wholesale Transmission Service Requirements	63
4	Minimum Distribution System Analysis	64

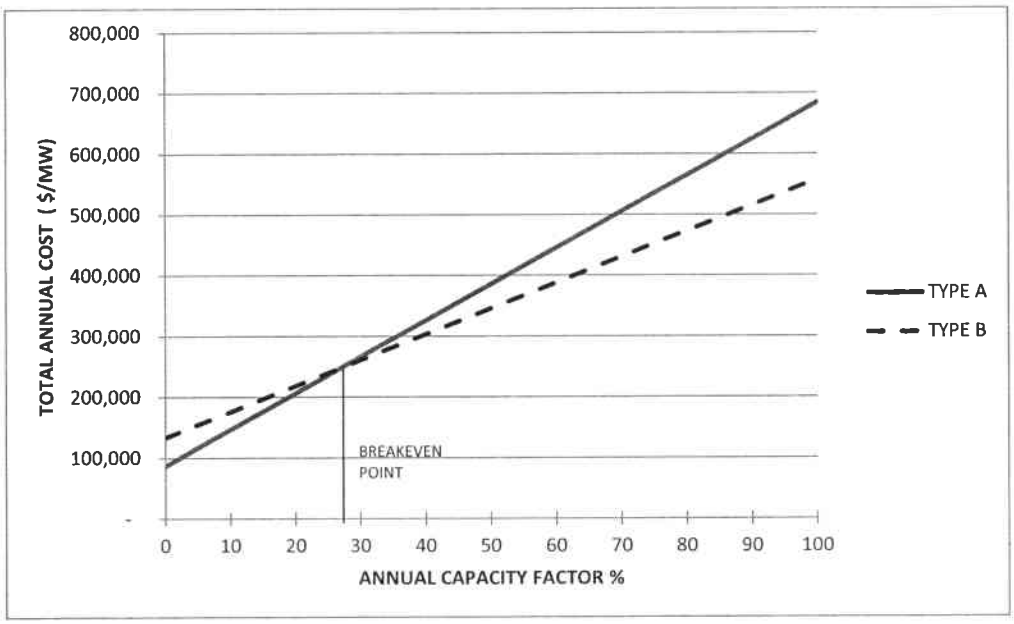
Illustration of Economic Generation Selection and Allocated Cost Determination

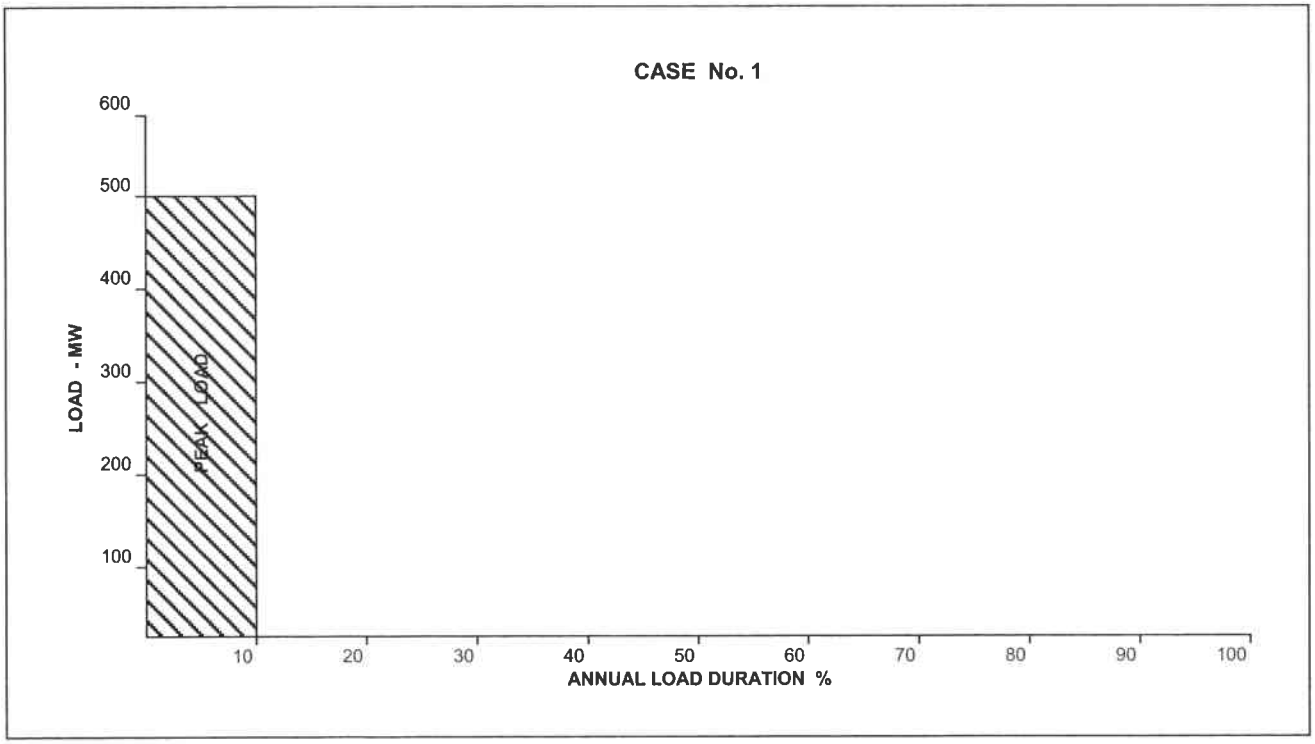
Comparative Costs of Generation Types*

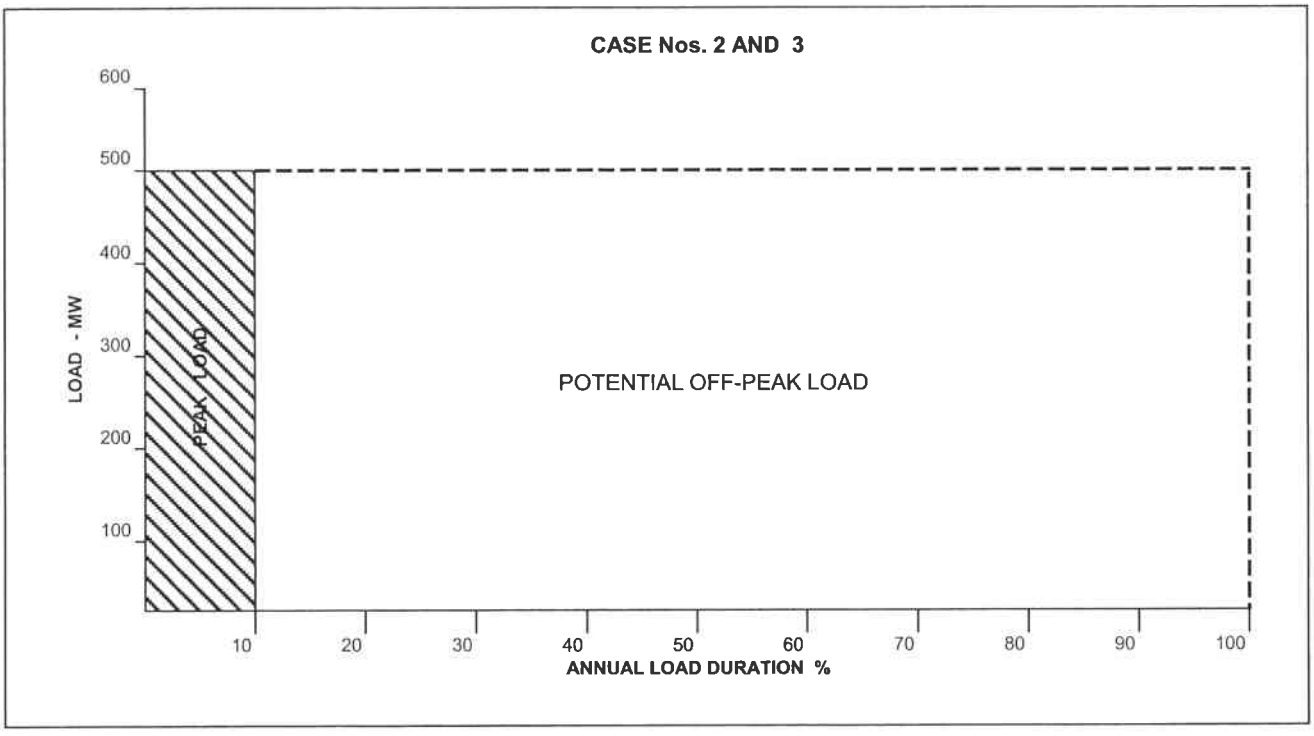
	Generation Type	(1) Total Annual Fixed Cost $/MW	(2) Total Annual Variable Cost $/MWH
A	Advanced Combustion Turbine	86,724	68.20
B	Conventional Combined Cycle	133,371	48.40

Economic Breakeven Capacity Factor = 26.9%

* Source: Direct Testimony of Stephen J. Baron, Docket No. 130040, page 16 of 41, taken from EIA's January 2013 Report entitled "Levelized Cost of New Generation Resources" in the Annual Energy Outlook 2013.




CASE No. 1
600
500
400
300
200
100
LOAD - MW
PEAK LOAD
10
20
30
40
50
60
70
80
90
100
ANNUAL LOAD DURATION %


CASE Nos. 2 AND 3
600
500
400
300
200
100
LOAD - MW
PEAK LOAD
POTENTIAL OFF-PEAK LOAD
10
20
30
40
50
60
70
80
90
100
ANNUAL LOAD DURATION %

Case No. 1
500 MW of Peak Load Only at 10% Annual Load Factor
Production Capacity Allocation Methodology: Peak

Requirements:							
Capacity	500	MW					
Energy	438,000	MWH	[10% annual capacity factor]				
Generation Selection: Type A							
Annual Costs:							
Capital	500	MW	x	$ 86,724	/MW	=	$ 43,362,000
Operating	438,000	MWH	x	$ 68.200	/MWH	=	$ 29,871,600

Allocated Class Cost of Service Study

		Total System	Rate Classes	
			Peak	Off-Peak
Allocation Factors:				
Peak	MW	500	500	0
	%	100.00%	100.00%	0.00%
AD Energy	MWH	438,000	438,000	0
	%	100.00%	100.00%	0.00%
Allocated Costs:				
	Allocation Factor			
Capital	P	$ 43,362,000	$ 43,362,000	$ -
Operating	AD	$ 29,871,600	$ 29,871,600	$ -
Total		$ 73,233,600	$ 73,233,600	$ -
MWH Sales		438,000	438,000	-
Total Allocated Cost - $ per MWH		$ 167.20	$ 167.20	n/a

Case No. 2:
500 MW of Peak Load at 10% Annual Load Factor and Potential Off-Peak Load
Production Capacity Allocation Methodology: Peak

Requirements:							
Capacity	500	MW					
Energy	4,380,000	MWH	[100% annual capacity factor]				
Generation Selection: Type B							
Annual Costs:							
Capital	500	MW	x	$	133,371	/MW	= $ 66,685,500
Operating	4,380,000	MWH	x	$	48.40	/MWH	= $ 211,992,000

Allocated Class Cost of Service Study

		Total System	Rate Classes	
			Peak	Off-Peak
Allocation Factors:				
Peak	MW	500	500	0
	%	100.00%	100.00%	0.00%
AD Energy	MWH	4,380,000	438,000	3,942,000
	%	100.00%	10.00%	90.00%
Allocated Costs:				
	Allocation Factor			
Capital	P	$ 66,685,500	$ 66,685,500	$ -
Operating	AD	$ 211,992,000	$ 21,199,200	$ 190,792,800
Total Allocated Cost		$ 278,677,500	$ 87,884,700	$ 190,792,800
MWH Sales		4,380,000	438,000	3,942,000
Total Allocated Cost - $ per MWH		$ 63.63	$ 200.65	$ 48.40

Case No. 3
500 MW of Peak Load at 10% Annual Load Factor and Potential Off-Peak Load
Production Capacity Allocation Methodology: Peak & 50% Avg. Demand

Requirements:							
Capacity	500	MW					
Energy	4,380,000	MWH	[100% capacity factor]				
Generation Selection: Type B							
Annual Costs:							
Capital	500	MW	x	$	133,371	/MW	= $ 66,685,500
Operating	4,380,000	MWH	x	$	48.40	/MWH	= $ 211,992,000

Allocated Class Cost of Service

		Total System	Rate Classes	
			Peak	Off-Peak
Allocation Factors:				
Peak	MW	500	500	0
	%	100.00%	100.00%	0.00%
AD Energy	MWH	4,380,000	438,000	3,942,000
	%	100.00%	10.00%	90.00%
Allocated Costs:				
Capital	Allocation Factor			
	50% P	$ 33,342,750	$ 33,342,750	$ -
	50% AD	$ 33,342,750	$ 3,334,275	$ 30,008,475
Total		$ 66,685,500	$ 36,677,025	$ 30,008,475
Operating	AD	$ 211,992,000	$ 21,199,200	$ 190,792,800
Total Allocated Cost		$ 278,677,500	$ 57,876,225	$ 220,801,275
MWH Sales		4,380,000	438,000	3,942,000
Total Allocated Cost - $ per MWH		$ 63.63	$ 132.14	$ 56.01

TAMPA ELECTRIC COMPANY
TEST PERIOD: PROJECTED CALENDAR YEAR 2014
COMPARISON OF CLASS COST RESULTS BY PRODUCTION CAPACITY ALLOCATION METHOD
Dollars in 000's

Line	Rate Class	(A) Present Methodology 12 CP and 25% AD: Base Rate Cost of Service	(B) Present Methodology 12 CP and 25% AD: Non-Fuel Cost Recovery Clauses	(C) Present Methodology 12 CP and 25% AD: Total Non-Fuel Cost (A) + (B)	(D) Prior Methodology 12 CP and 1/13th AD: Base Rate Cost of Service	(E) Prior Methodology 12 CP and 1/13th AD: Non-Fuel Cost Recovery Clauses	(F) Prior Methodology 12 CP and 1/13th AD: Total Non-Fuel Cost (D) + (E)	(G) Proposed Methodology 12 CP and 50% AD: Base Rate Cost of Service	(H) Proposed Methodology 12 CP and 50% AD: Non-Fuel Cost Recovery Clauses	(I) Proposed Methodology 12 CP and 50% AD: Total Non-Fuel Cost (G) + (H)	(J) Total Difference: 25%AD vs. 1/13th AD: $ (C) - (F)	(K) Total Difference: 25%AD vs. 1/13th AD: % (J) / (F) *100%	(L) Total Difference: 25%AD vs. 1/13th AD: Effective $ / MWH (J) / Sales	(M) Total Difference: 50%AD vs. 25% AD: $ (I) - (C)	(N) Total Difference: 50%AD vs. 25% AD: % (M) / (C) *100%	(O) Total Difference: 50%AD vs. 25% AD: Effective $ / MWH (M) / Sales
1	I. Residential (RS,RSVP)	576,982	92,189	669,171	583,604	93,291	676,895	567,417	90,597	658,014	(7,724)			(11,157)		
3	II. General Service															
4	Non-Demand (GS,TS)	64,986	10,703	75,689	65,361	10,757	76,118	64,444	10,622	75,066	(429)			(623)		
5	Sub-Total: I. + II.	641,968	102,892	744,860	648,965	104,048	753,013	631,861	101,219	733,080	(8,153)	-1.1%	(0.85)	(11,780)	-1.6%	(1.23)
6	III. General Service															
7	Demand (GSD, SBF)	336,778	74,696	411,474	332,156	73,829	405,985	343,454	75,943	419,397	5,489			7,923		
8	IV. Interruptible Service (IS)	25,237	7,858	33,095	23,713	7,697	31,410	27,438	8,097	35,535	1,685			2,440		
9	Sub-Total: III. + IV.	362,015	82,554	444,569	355,869	81,526	437,395	370,892	84,040	454,932	7,174	1.6%	0.84	10,363	2.3%	1.21
10	V. Lighting (LS-1)															
11	A. - Energy	6,752	1,684	8,436	5,901	1,556	7,457	7,982	1,871	9,853	979	13.1%	4.43	1,417	16.8%	6.41
12	B. - Facilities	31,875	-	31,875	31,875	-	31,875	31,875	-	31,875	-	0.0%	na	-	0.0%	na
13	Total	1,042,610	187,130	1,229,740	1,042,610	187,130	1,229,740	1,042,610	187,130	1,229,740	0.00	0	0.00	0.00	0.0%	0.00

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
EXHIBIT NO. ____ (WRA-2)
WITNESS: ASHBURN
DOCUMENT NO. 2
PAGE 1 OF 1
FILED: 08/08/2013

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
13-MONTH AVERAGE RATE BASE
2014 TEST YEAR
RETAIL JURISDICTIONAL AMOUNTS ($ 000's)
PER JURISDICTIONAL SEPARATION STUDY

	Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP	Plant Held for Future Use	Net Plant	Working Capital	Total Rate Base
Original Filing	6,506,194	(2,436,894)	4,069,300	174,146	35,409	4,278,855	61,119	4,339,974
Adjustments:								
Calpine Update	(40,447)	12,002	(28,445)	(1,508)	(1,775)	(31,728)	261	(31,467)
APP Update	0	0	0	0	0	0	0	0
Total Adjustments	(40,447)	12,002	(28,445)	(1,508)	(1,775)	(31,728)	261	(31,467)
Adjusted Filing	6,465,747	(2,424,892)	4,040,855	172,638	33,634	4,247,127	61,380	4,308,507

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
NET OPERATING INCOME
2014 TEST YEAR
RETAIL JURISDICTIONAL AMOUNTS ($ 000's)
PER JURISDICTIONAL SEPARATION STUDY

	Operating Revenues	O&M - Fuel & Purchased Power	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
Original Filing	950,664	9,301	354,533	233,881	65,789	77,391	(132)	740,763	209,901
Adjustments:									
Calpine Update	(102)	0	(1,169)	(1,172)	(381)	1,252	1	(1,469)	1,367
APP Update	0	0	0	0	0	0	0	0	0
Total Adjustments	(102)	0	(1,169)	(1,172)	(381)	1,252	1	(1,469)	1,367
Adjusted Filing	950,562	9,301	353,364	232,709	65,408	78,643	(131)	739,294	211,268

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
EXHIBIT NO. ____ (WRA-2)
WITNESS: ASHBURN
DOCUMENT NO. 3
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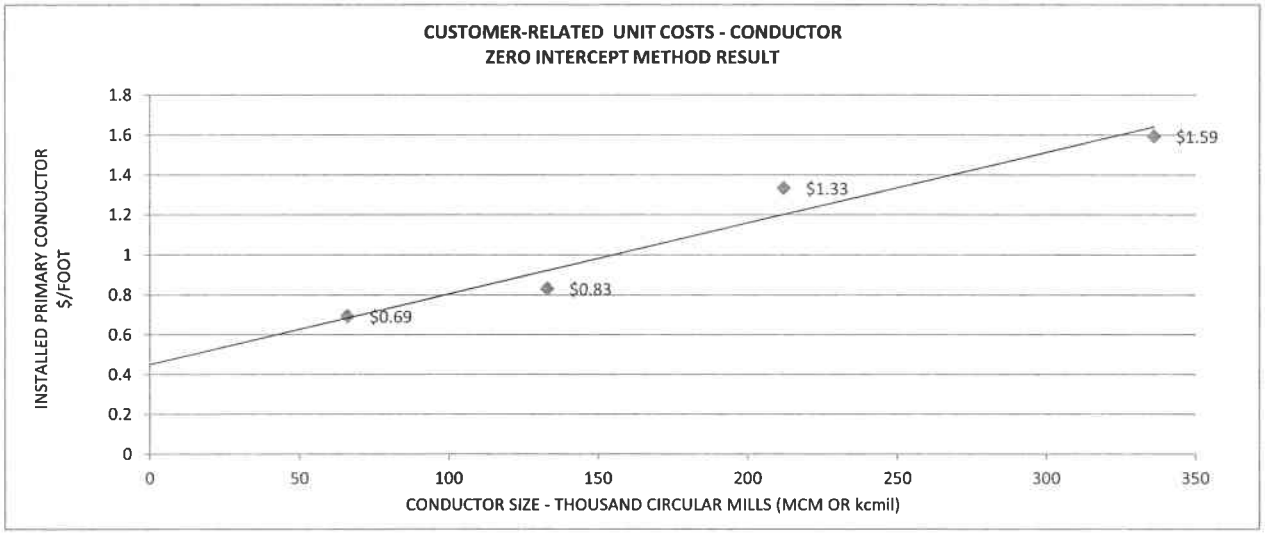
FILED: 08/08/2013

MINIMUM DISTRIBUTION SYSTEM ANALYSIS



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.973399098
R Square	0.947505804
Adjusted R Square	0.921258707
Standard Error	0.118552371
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.507365671	0.507365671	36.09945034	0.026600902
Residual	2	0.028109329	0.014054665		
Total	3	0.535475			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 90.0%*	*Upper 90.0%*
Intercept	0.450553021	0.125106473	3.601356601	0.06919529	-0.087736685	0.988842726	0.085243925	0.815862117
X Variable 1	0.003544562	0.000589946	6.008281813	0.026600902	0.001006229	0.006082895	0.001821928	0.005267196

MINIMUM DISTRIBUTION SYSTEM ANALYSIS
ACCOUNTS' 365 & 367 - CONDUCTORS AND DEVICES

Line No.				Reference Note
1	Minimum size conductor current cost based on zero-intercept determination in $/ft.	$	0.45	a
	Times:		x	
2	Total footage quantity of conductors installed in A/C's 365 & 367		187,550,988	b
	Equals:			
3	Total current cost of conductors in A/C 367 valued on basis of minimum unit cost	$	84,397,945	
	Times:		x	
4	Ancillaries Factor		1.26	c
	Equals:			
5	Total current cost of all facilities in A/C's 365 & 367 valued on basis of minimum unit cost	$	106,341,410	
	Divided by:		/	
6	Total Estimated Replacement Cost of Accounts 365 & 367	$	1,138,119,878	d
	Equals:			
7	Calculated % Customer Cost Component of Accounts 365 & 367- Conductors & Devices		9%	

Notes:

a Per zero-intercept calculation for conductors.

b Per Plant Accounting Dept.'s detailed records of facilities in A/C's 365 & 367 as of EOY 2011.

c Reflects proportional cost of ancillary facilities in Plant Accounting's records for A/C 365 & 367 that support the conductors' units of property.

d Per input data to TECO's most recent Storm Damage Study.
Account 366, conduit, is assumed to have same classification as being derived herein for account 367.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
EXHIBIT NO. ____ (WRA-2)
WITNESS: ASHBURN
DOCUMENT NO. 4
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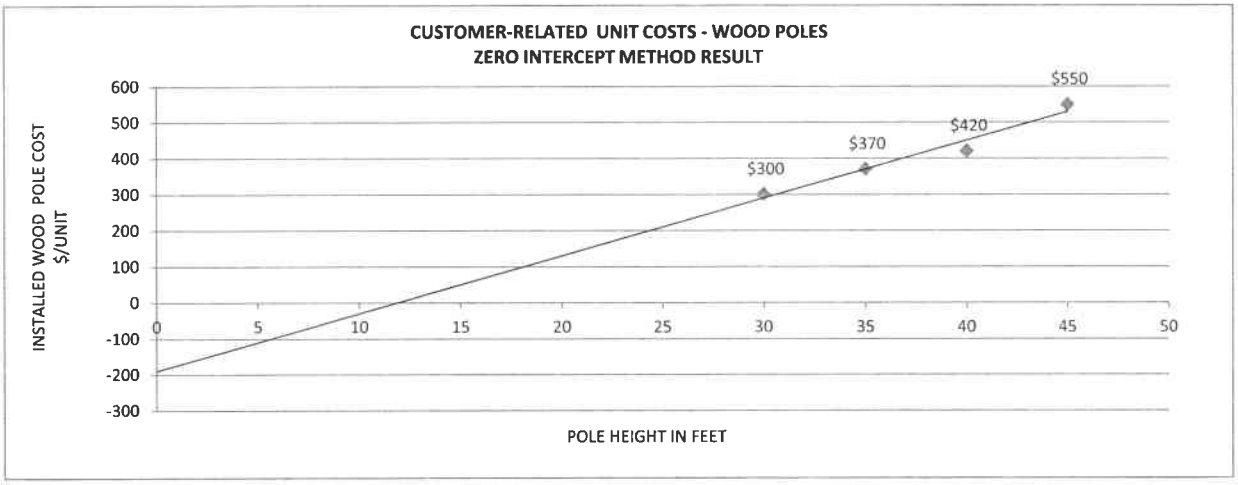
FILED: 08/08/2013

MINIMUM DISTRIBUTION SYSTEM ANALYSIS



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.978817568
R Square	0.958083832
Adjusted R Square	0.937125749
Standard Error	26.45751311
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	32000	32000	45.71428571	0.021182432
Residual	2	1400	700		
Total	3	33400			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 90.0%*	*Upper 90.0%*
Intercept	-190	89.72179222	-2.117657208	0.168392592	-576.0417142	196.0417142	-451.9863395	71.98633954
X Variable 1	16	2.366431913	6.761234038	0.021182432	5.818065269	26.18193473	9.090052936	22.90994706

TECO
TAMPA ELECTRIC

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI

IN RE: TAMPA ELECTRIC COMPANY'S

PETITION FOR AN INCREASE IN BASE RATES

AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT

OF

KAREN J. LEWIS

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

KAREN J. LEWIS

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

A. My name is Karen J. Lewis. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Customer Services.

Q. Please describe your educational background and business experience.

A. In 1984, I received a Bachelor's of Science in Industrial Engineering from Auburn University. Upon graduation I joined Gulf Power Company, where I worked for two years before joining Progress Energy and working there from 1987 to 2001. In 2001, I joined Tampa Electric as a Director in Energy Delivery where I worked in various management roles until 2009. In 2009, I became Director Customer Services for Tampa Electric and Peoples Gas, which is my current position.

Q. What are your responsibilities as the Director of Customer Services?

A. I have responsibility for the following Customer Service functions for both Tampa Electric and Peoples Gas. The functions include, but are not limited to the call center front line operations, call center support functions (training, workforce scheduling, workforce performance metrics), billing, payments, credit and collections and escalated customer complaints.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address errors and shortcomings in the prepared direct testimony of witnesses Helmuth W. Shultz, III, and Donna Ramas, testifying on behalf of the Office of Public Counsel ("OPC") and Lane Kollen testifying on behalf of the West Central Hospital Utility Alliance ("HUA").

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes, I have. My Exhibit No.__ (KJL-1), consisting of four documents, was prepared by me or under my direction

and supervision.

Document No. 1	JD Power & Associates Survey Results 2010-2013
Document No. 2	Call Center Staffing and Service Levels 2009-2013
Document No. 3	Write Off Trends 2008-2012
Document No. 4	Florida Public Service Commission ("FPSC") Complaint Trends 2008-2013

Q. Please summarize the key concerns and disagreements you have regarding the substance of witnesses Shultz's, Ramas's and Kollen's testimonies.

A. My key concerns and disagreements are as follows:

1. I disagree with witness Shultz's assertion that an adjustment to remove 104 of the 114 positions in the company's test year is appropriate. Of those 114 positions, 16 are customer service related positions that are essential to maintain appropriate service levels and minimize uncollectible revenues. The Commission should not make an adjustment to reduce operations and maintenance ("O&M") expense for these 16 positions.
2. I disagree with witness Ramas's and witness Kollen's

position that a reduction to uncollectible expense is appropriate. I will explain how the company's efforts to reduce bad debt have benefited customers and why the expense level requested by the company is reasonable, prudent and necessary.

3. I disagree with witness Kollen's position that a reduction of call center expense is appropriate. I will explain the drivers for incremental call center expense and why those expenses are appropriate, reasonable and prudent to maintain adequate customer service levels.

APPROPRIATE HEADCOUNT LEVELS

Q. Are additional call center positions necessary to maintain and improve service levels?

A. Yes. Of the proposed headcount reductions in witness Shultz's testimony, 16 of the 104 are in Customer Service. Of those 16 positions, 12 are in the call center, three are in Billing & Payments and one is an Administrative Assistant.

Call center Representative staffing in 2012 was well below historical levels. In 2012, call center staffing was reduced in an effort to control costs by cancelling

new hire classes and not addressing normal attrition with new hires. Staffing reductions had a negative effect on customer service levels, which is reflected in the company's JD Power & Associates survey results shown in Document No. 1 of my exhibit. In order to address the decline in customer service levels, in 2013, 12 additional call center Representatives were hired. As a result, call center response times and customer satisfaction have improved.

Q. What positions have been filled or are being budgeted to be filled in 2014?

A. As of the date of the filing of this rebuttal testimony, the company has filled 16 of the 16 customer service positions that witness Schultz has proposed to adjust. Of the 16 who have been hired, 14 are front line customer service agents who spend the vast majority of their time dealing directly with customers. The other two positions provide administrative support for Customer Service.

A Senior Administrative Specialist was hired to provide support to the Director and three Managers, and that position is the only administrative support for that group. An Administrative Specialist vacancy in Billing &

Payments was filled because the incumbent was promoted to another position within the company. This vacancy was filled in 2013, and that position is the sole administrative support for 32 team members. Finally, two Billing Payment Specialists were hired in 2012 to help handle the increasing workload within the department.

Q. What functions do call center Representatives perform that impact customer satisfaction?

A. The company has two call center locations, one in Tampa and one in Plant City. Together, the two call centers employ 108 call center representatives. Customers can reach the call centers through a local or toll free number. Calls are passed through an Integrated Voice Response ("IVR") system to enable self-service options. Approximately 50 percent of the inbound customer calls are serviced within the IVR. The remaining 50 percent of our customers that elect to speak with a representative are routed to the first available agent. As one would expect, lower staffing levels result in longer wait times for customers that need to speak with a representative.

Q. What metrics does the company monitor to assess the level of customer service provided by the call centers?

A. The time it takes for a customer to speak with a representative is represented in the Customer Service Professional ("CSP") Service Level metric and the Average Speed of Answer ("ASA") metric shown in Document No. 2 of my exhibit. The company strives to answer at least 65 percent of these calls within 30 seconds. In 2011, there were 109 agents handling customer calls, and the CSP Service Level was 70 percent. In 2012, there were 98 agents handling residential calls, and the CSP Service Level dropped to 53 percent. The service level metric shows the direct correlation between call center service levels and customer satisfaction. The decline in call center response time and the desire to continue improving response times is why the company increased the number of team members employed at the call centers.

Q. Do you believe the company will be able to maintain its level of customer service in the call center if the Commission accepts witness Schultz's proposed elimination of 16 call center positions?

A. No, I do not. The company needs the additional positions to improve customer service and cannot reduce those positions without jeopardizing service levels.

CALL CENTER EXPENSES

Q. Do you agree with witness Kollen's statement that test year call center expenses have not been justified?

A. No. As previously stated, the company has already added 12 call center agents in 2013, resulting in an incremental annual labor cost of $550,000. Call center staffing was reduced in 2012 as a means to reduce costs. As a result, customer service levels and customer satisfaction declined. The 12 positions added in 2013 restored staffing to previous levels. Document Nos. 1 and 2 of my exhibit illustrate the correlation between resources, customer satisfaction and customer service levels.

Q. How is the call center performance tracked?

A. The call center uses qualitative and quantitative measures to evaluate performance. The company strives for a high level of customer satisfaction, and the call center places a great deal of focus on meeting the individual needs of each customer in an efficient, effective and pleasant manner. The qualitative measures include monitoring 100 percent of the calls and supervisor monitoring of a sufficient number of calls to

ensure that CSP agents are meeting expectations. A Quality Assurance team also takes samples of calls from all representatives and evaluates the agents' performances. Other quantitative measures include the ASA and the CSP Agent's Service Level.

Q. What does the company consider to be acceptable call center performance and how has the company performed over the past several years?

A. The company strives to answer 65 percent of customer calls within 30 seconds. The company also focuses on other metrics such as ASA and the percent of calls that are abandoned (customer hangs up due to extended wait time). Historical 2009 through 2013 call center performance is illustrated in Document No. 2 of my exhibit. In late 2012, the call center dedicated a great deal of time and resources toward implementing an initiative known internally as "WOW". An outside consultant was brought in that had worked with numerous call centers for electric utilities. The consultant spent six months working with call center management. The WOW initiative focused on front line supervisors first and involved a great deal of training for the supervisors. Once management training was complete, the

CSP Agents were trained and they are continuously evaluated on WOW principles. This program has been very effective and has contributed to the increase in customer satisfaction in 2013.

Q. How does the company measure customer satisfaction?

A. Customer satisfaction is measured in various ways. The company started an after call survey in 2013 to solicit direct feedback from customers. Approximately 1,400 customers per month are surveyed and about 19 percent complete the survey. Year to date, an 82 percent favorability level has been achieved in survey responses. Similarly, JD Power & Associates surveys approximately 250 customers each quarter. JD Power & Associates survey results (specific to the call center) declined when the number of CSP agents decreased in 2012. After hiring 12 call center agents earlier this year, JD Power & Associates' scores have improved. The company also looks at customer complaint activity to gauge customer satisfaction. FPSC complaints have decreased over the past several years as reflected in Document No. 4 of my exhibit.

Q. Do you agree with witness Kollen's testimony that the

$1.9 million dollar increase in expenses from 2012 to 2014 is not justified?

A. No. The increase in call center expenses from 2012 to 2014 is due primarily to increased labor and vendor maintenance costs. The call center budget increased $861,000 from 2012 to 2013 due to the aforementioned 12 additional CSP agents, merit increases for all call center employees, costs associated with agent attrition, maintenance and licensing fees associated with the new Contact Center Manager ("CCM") application. In a typical year, the call center loses up to 25 percent of CSP agents due to promotion, resignation or termination. To mitigate this attrition, two or three new hire classes are needed each year. When CSP agents are hired, staffing levels increase above our targeted average. The temporary increase is intentional as new hires are in training for nine weeks post-hire and therefore not fully productive; and attrition will gradually lower headcount over the upcoming months to the targeted average headcount.

Q. What is the CCM application and how will it improve customer service?

A. The CCM application will be implemented in late 2013 and consists of an improved, customer-centric IVR and advanced workforce optimization tools. The existing IVR is challenging for customers to navigate, and the company is responding to customer concerns by implementing a new and improved IVR application. The CCM also includes Call Back Request. If a Call Center agent is not able to pick up the customer's call immediately, the customer can elect a call back instead of being placed on hold. The CCM will also enable advanced workforce scheduling and reporting tools for individual agents, thus increasing the productivity and efficiency of the call center. This CCM application requires annual maintenance and licensing fees of approximately $200,000.

Q. Do you agree with witness Kollen's testimony that the company failed to explain why other communication tools (including customer service interaction portal) has not relieved pressure on the call center?

A. The company does not understand witness Kollen's definition of "customer service interaction portal". But I will describe the mechanisms in place for customers to interact with CSP agents. Customers can reach the call center via local and toll free phone numbers. The

previously mentioned CCM application will enhance the customer's phone interactions with the company.

The company also implemented Power Updates in June 2013. This service enables two way communications between the company and customers on power outages. Previously, customers called the company's outage reporting phone number to report an outage. Power Updates enables customers to use various modes of technology (mobile phone, tablet, and email or land-line phone) to report outages and to receive updates from the company on restoration status. The main benefit of the Power Updates application is that it enables customers to communicate with the company by means other than a phone call. This provides customer convenience and a positive influence on customer satisfaction. While it is certainly a beneficial customer resource, the application does not influence labor resource needs.

UNCOLLECTIBLE EXPENSE LEVELS

Q. Do you agree with witness Ramas's testimony that Tampa Electric's test year budgeted uncollectible expense is excessive?

A. No. The test year budgeted uncollectible expense is

reasonable.

Q. What are your responsibilities in the areas of bad debt collection and bad debt expense?

A. I am responsible for the development and implementation of strategies related to managing and minimizing the company's uncollectible expense. This includes ensuring customers' accounts are properly secured with deposits. It also includes the management of collections on bad debt, prevention of bad debt and policies that target the identification of lost revenue as well as fraud prevention.

Q. What is bad debt expense?

A. Bad debt expense is the uncollectible revenues which can result from overdue/late payment of bills or customers vacating a premise with outstanding balances.

Q. Witness Ramas proposes that the test year uncollectible expense be based on the actual 2012 ratio of net write-offs to revenues. Do you believe that is appropriate?

A. No. Using the 2012 ratio of net write-offs to revenues

does not take into account unique circumstances in 2012 that resulted in a significant reduction in uncollectible expenses. The 2014 test year uncollectible expense represents our expected future uncollectible expense and includes the impact of the new Credit and Collections System and other ongoing initiatives to reduce write offs.

Q. How does the company's proposed level of uncollectible expense in the test year compare to industry averages and the company's historical experience?

A. The test year net write-offs to revenues is 0.19 percent which is significantly lower than the industry average of 0.44 percent[1]. The 2014 test year net write-offs to revenues is also lower than the company's five year average of 0.28 percent. Write-offs fluctuate from year to year and are often influenced by economic conditions. The write-offs for 2012 were unusually low.

Q. What unique circumstances occurred in 2012 that affected the uncollectible expenses?

A. The company implemented a new collections system called DebtNext. DebtNext replaced a system that was 20 years old and reduces or eliminates manual work associated with

[1] Chartwell Facilitating Knowledge Exchange; Report on Credit and Collections in the Utility Industry 2010 © Chartwell Inc. 2010

the credit and collections process. This system is a vast improvement in how the company manages debt and has enabled the company to successfully collect on numerous accounts that had previously not tracked with the old system.

Q. Please describe the new systems and how they have helped reduce the level of uncollectible expense.

A. DebtNext searches outstanding account balances for uncollected debt and attempts to match these accounts with active accounts by name or social security number. When a match is determined and the transfer balance process begins, the system will generate letters advising the customer than an unpaid balance has been located and transferred to their account. If, after 60 days the payment has not been received, DebtNext automatically sends the account to the collection agency for recovery.

Q. What sustainable initiatives have been implemented that will keep uncollectible expense lower than pre-2011 levels?

A. The company developed many initiatives over the past several years to minimize uncollectible expense. The new

Credit and Collections System, DebtNext, has been discussed, and there are two other major initiatives that have impacted uncollectible expense. The company sharpened its procedures to ensure that it can positively identify customers applying for service. The company uses an outside vendor (Equifax) to validate the identification of new customers by confirming credit information, e.g., social security numbers or driver's license information to confirm the identity of the person applying for service. These procedures were implemented in 2010 and have had a positive effect on write-offs and fraud. Over the last several years, there has also been a focus on customer deposits, including an extensive review of all residential, commercial and industrial accounts to ensure all customer accounts were adequately secured.

Q. Have these new systems and initiatives shown positive results?

A. Yes. Document No. 3 of my exhibit illustrates the revenues and net write-off trends from 2008 through 2012. The average net write-offs from 2008 through 2012 was $5.7 million or 0.28 percent of revenue. After DebtNext was implemented in April 2011, the company experienced

the peak benefit of the new system as net write-offs dropped to $2.3 million or 0.122 percent of revenue. DebtNext has now completed the full review of all existing debt and has exhausted any further matches with active customers for collection. Therefore, the low level of 2012 write-offs was a unique situation that is not sustainable. While the company expects that the DebtNext system will prevent write-offs from climbing back to the pre-2011 levels, the 2012 write-off level was a result of the system working through the company's existing customer base and capturing uncollectible expenses that were not detected in the past.

The 2014 test year uncollectible expense of $3.6 million is a reasonable estimate of the annual expected uncollectible expense. The company will continue to make all efforts to hold write-offs at or below this level going forward. However, the 2014 proposed test year uncollectible expense of $3.6 million is considerably lower than the 2008 through 2012 average of $5.7 million and should be approved.

Summary of Rebuttal Testimony

Q. Please summarize your rebuttal testimony.

A. The company has justified that its requested level of call center expense for 2014 is appropriate. Staffing levels declined considerably from 2011 to 2012, resulting in lower service levels and decreased customer satisfaction. The increase in customer service expense between 2012 and 2014 expense is primarily due to reaching and maintaining appropriate staffing levels, merit increases, and increased maintenance/license expense associated with a new CCM program.

The company has also justified its requested level of uncollectible expense for the 2014 test year as reasonable. The five-year average for write-offs is $5.7 million or 0.28 percent of revenue. The test year budget of $3.6 million or 0.19 percent of revenues is well below the five-year average. The company has implemented various programs, policies and procedures to lower write-offs; however, the 2012 levels should not be considered a baseline year because the implementation of a new collections system distorted that year's write-offs as a percentage of revenue statistics.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
WITNESS: LEWIS

EXHIBIT

OF

KAREN J. LEWIS

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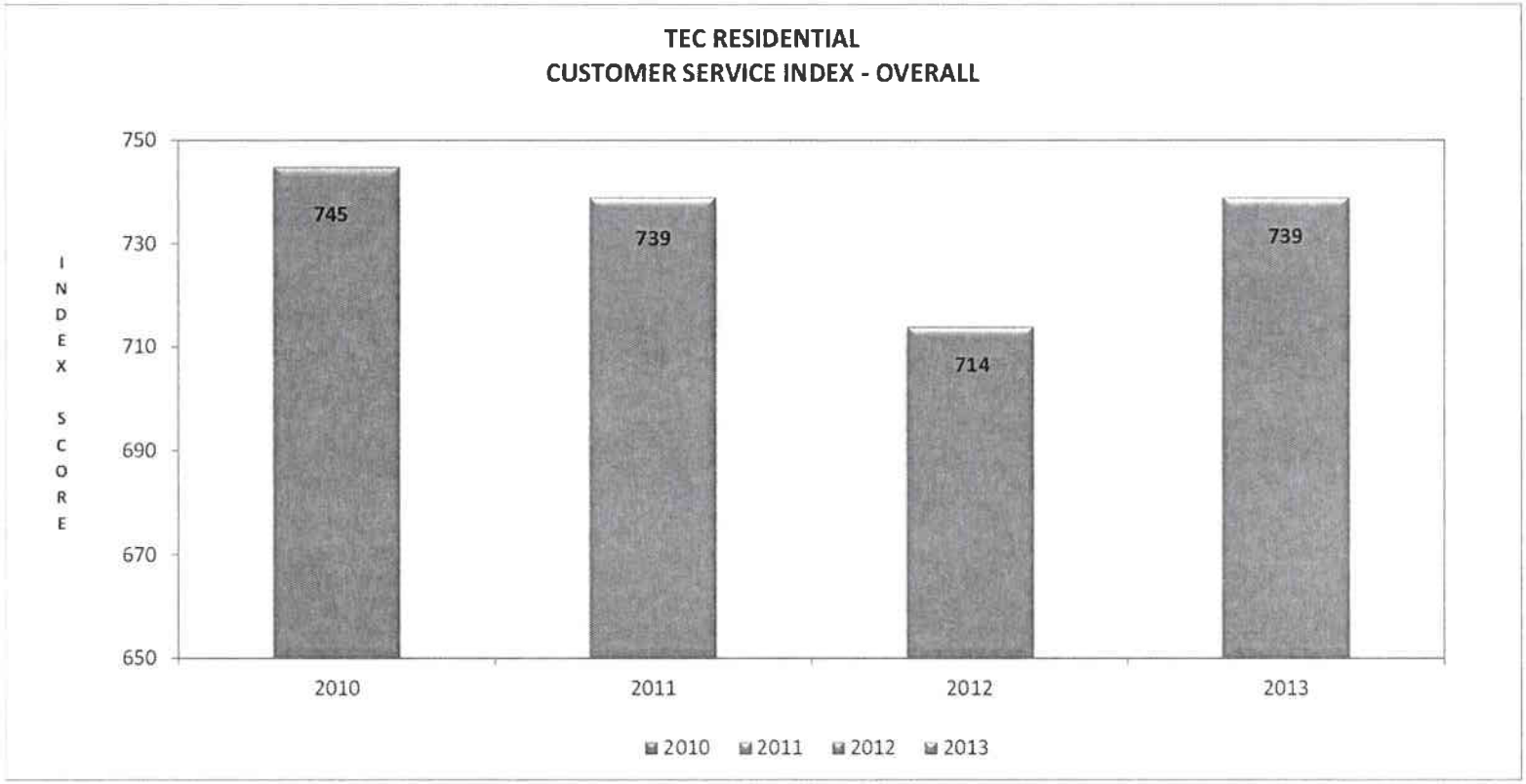
3	Write Off Trends 2008-2012	24
4	FPSC Complaint Trends 2008-2013	25

JD Power Survey Results 2010-2013
Customer Service Index – Overall
July 2013



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	Call Center Staffing	CSP Service Level (% answered in 30 seconds)	% Calls Abandoned	Avg. Speed of Answer (ASA)
2013	108	60%	9%	2:08
2012	98	53%	12%	3:13
2011	109	70%	4%	1:01
2010	113	71%	3%	1:12
2009	114	41%	12%	1:38

Tampa Electric Company
Write Off Trends 2008-2012

	2008	2009	2010	2011	2012	Average (2008-2012)
Revenues	$1,996,492,000	$2,185,915,000	$2,127,810,000	$1,974,385,000	$1,953,721,000	$2,047,575,000
Net Write-off	$ 6,711,705	$ 7,274,039	$ 7,741,185	$ 4,468,929	$ 2,373,676	$ 5,713,907
Write Off Percentage	0.329%	0.328%	0.364%	0.226%	0.122%	0.279%

TAMPA ELECTRIC COMPANY
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Tampa Electric FPSC Complaint Activity

Complaint type	2008	2009	2010	2011	2012	2013 YTD. 6/30/13
Informal Transfer-Connect Calls	709	771	709	606	483	145
Formal complaints	204	207	234	163	112	55
Infractions	1	8	6	3	2	1

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130040-EI
IN RE: TAMPA ELECTRIC COMPANY'S PETITION FOR AN INCREASE IN BASE RATES AND MISCELLANEOUS SERVICE CHARGES

REBUTTAL TESTIMONY AND EXHIBIT
OF
TERRY DEASON
ON BEHALF OF TAMPA ELECTRIC COMPANY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

TERRY DEASON

ON BEHALF OF TAMPA ELECTRIC COMPANY

Q. Please state your name and business address.

A. My name is Terry Deason. My business address is 301 S. Bronough Street, Suite 200, Tallahassee, Florida 32301.

Q. By whom are you employed and in what capacity?

A. I am employed by the Radey Law Firm as a Special Consultant specializing in the fields of energy, telecommunications, water and wastewater, and public utilities generally.

Q. Please describe your educational background and professional experience.

A. I have thirty-six years of experience in the field of public utility regulation spanning a wide range of responsibilities and roles. I served a total of seven years as a consumer advocate in the Florida Office of

Public Counsel ("OPC") on two separate occasions. In that role, I testified as an expert witness in numerous rate proceedings before the Florida Public Service Commission ("Commission"). My tenure of service at the Florida Office of Public Counsel was interrupted by six years as Chief Advisor to Florida Public Service Commissioner Gerald L. Gunter. I left OPC as its Chief Regulatory Analyst when I was first appointed to the Commission in 1991. I served as Commissioner on the Commission for sixteen years, serving as its chairman on two separate occasions. Since retiring from the Commission at the end of 2006, I have been providing consulting services and expert testimony on behalf of various clients, including public service commission advocacy staff and regulated utility companies, before commissions in Arkansas, Florida, Montana, New York and North Dakota. My testimony has addressed various regulatory policy matters, including: regulated income tax policy; storm cost recovery procedures; austerity adjustments; depreciation policy; subsequent year rate adjustments; appropriate capital structure ratios; and prudence determinations for proposed new generating plants and associated transmission facilities. I have also testified before various legislative committees on regulatory policy matters. I hold a Bachelor of Science

Degree in Accounting, summa cum laude, and a Master of Accounting, both from Florida State University.

Q. Have you prepared an exhibit supporting your Rebuttal Testimony?

A. Yes, I have. My Exhibit No.__ (TD-1), consisting of three documents, was prepared by me or under my direction and supervision. These consist of:

Document No. 1: Biographical Information for Terry Deason

Document No. 2: Consulting Services and Expert Testimony Provided by Terry Deason

Document No. 3: Amortization of a $10 Million Hypothetical Investment

Q. For whom are you appearing as a rebuttal witness?

A. I am appearing as a rebuttal witness for Tampa Electric Company ("Tampa Electric" or "the company").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain assertions and recommendations made by intervenor

witnesses Chriss, Gorman, Kollen, Pous, and Schultz. The issues I address in rebuttal to these witnesses are: Projected Test Year; Construction Work In Progress; Reconciliation of Rate Base and Capital Structure; Operations & Maintenance Expenses; Equity Ratio; Amortization of Software; Incentive Compensation; and, Directors and Officers Liability Insurance.

PROJECTED TEST YEAR

Q. What is the test year being used in this proceeding?

A. A 2014 projected test year.

Q. What does witness Chriss say about the use of a projected test year?

A. Witness Chriss states that a projected test year reduces regulatory lag and suggests that its use should result in a lower return on equity ("ROE") for Tampa Electric. He goes on to quote from Order No. PSC-02-0787-FOF-EI.

Q. Do you agree with Witness Chriss?

A. I agree that the use of a projected test helps mitigate regulatory lag. I disagree with his suggestion that the

use of a projected test year should result in a lower ROE. Projected tests years are the established practice in Florida and have their origin as far back as 1983, when the Florida Supreme Court addressed the use of projected test years. In 443 So.2d 92, the Court stated:

> Nothing in the decisions of this Court or any legislative act prohibits the use of a projected test year by the Commission in setting a utility's rates. We agree with the Commission that it may allow the use of a projected test year as an accounting mechanism to minimize regulatory lag. The projected test period established by the Commission is a ratemaking tool which allows the Commission to determine, as accurately as possible, rates which would be just and reasonable to the customer and properly compensatory to the utility.

Given that projected test years are the established practice in Florida, their continued use is a reasonable expectation of investors and is already reflected in the market metrics used to estimate a regulated utility's cost of equity capital. Only if the Commission were to

revert to the use of historical test years would there be an impact on the capital markets. In that event, the cost of equity capital would likely be higher, not lower.

Q. Are you familiar with the Order cited by witness Chriss?

A. Yes, I am. This Order granted a rate increase to Gulf Power Company("Gulf") in 2002. The use of a projected test year was questioned by OPC, which sponsored the testimony of Helmuth W. Schultz III. Witness Schultz found fault with the projected test year and offered support for an adjusted historical year. The order stated:

> Witness Schultz testified that he made a number of adjustments based upon a historical level of spending that he considered sufficient to provide the quality of service. In his opinion, the historical spending should be used when establishing rates, especially when considering the lack of detail in the company's budget.

Q. What did the Commission decide?

A. While noting that historical and projected test years each have strengths and weaknesses, the Commission affirmed the use of a projected test year. In rejecting witness Schultz's approach, the Commission stated:

> The historical test year has the advantage of using actual data for much of rate base, NOI, and capital structure; however, the pro forma adjustments usually do not represent all the changes that occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.

Q. Is this finding instructive for the use of a projected test year for Tampa Electric in 2014?

A. Yes, very much so. While I am not aware of any direct challenge to the use of a projected test year for Tampa Electric, as was the case for Gulf, there are intervenor witnesses who indirectly challenge it. They do this by relying on an historical year adjusted for inflation or an average of a series of historical years to place a

limitation on costs eligible for recovery. Witness Kollen's use of a "top-down" approach based on 2012 to determine his recommended level of operations and maintenance (O&M) expenses is a good example. This approach and other adjustments recommended by witness Kollen and witness Schultz are essentially reverting to the use of a historical test year for selected issues. The regulatory policy shortcomings of their approach for certain issues are further addressed by me later in my testimony. More importantly, the fallacies of their positions are explained in greater detail by Tampa Electric operational witnesses. These witnesses explain how intervenor adjustments deny them the level of resources needed to reliably and effectively provide services in 2014 and beyond. Their testimony goes from regulatory theory to real world impacts of the intervenor adjustments.

Q. What is your recommendation?

A. I recommend that the Commission reaffirm the use of a projected test year and utilize Tampa Electric's 2014 projections as the basis to set rates in 2014 and beyond. Only if it is determined that the 2014 projections are biased, inherently flawed, or yield unreasonable results,

should there be adjustments. It is Tampa Electric's burden to demonstrate that their projections are appropriate and reasonable. However, a mere observation that the 2014 projections are greater than historical escalations or historical averages, as is done by various intervenor witnesses, is not sufficient to reject the projections out-of-hand and impose strict limitations on recoverable costs. As observed by the Florida Supreme Court, the ultimate goal is "to determine, as accurately as possible, rates which would be just and reasonable to the customer and properly compensatory to the utility." I fear that many of the historically based intervenor adjustments result in artificial limitations on otherwise prudent and necessary costs. As such, these adjustments would be inconsistent with this goal.

CONSTRUCTION WORK IN PROGRESS

Q. What is Construction Work In Progress?

A. Construction Work in Progress ("CWIP") is FERC Account 107 which reflects the total of work order balances for electric plant that is in the process of being constructed.

Q. Is CWIP a necessary part of providing quality utility

service?

A. Yes, it is. A well-managed utility focused on providing quality and cost effective service will deploy capital to construct new and/or modernize existing facilities to meet these objectives.

Q. Recognizing that CWIP is a necessary part of providing quality utility service, should it be permitted to earn a return?

A. Yes, it should.

Q. How should this be accomplished?

A. It should be accomplished in one of two ways. First, balances in CWIP could be allowed to accrue on Allowances for Funds Used During Construction ("AFUDC"). The Commission has adopted Rule 25-6.0141, F.A.C., which sets forth the calculation of AFUDC and the eligibility requirements of those construction projects which qualify. The second way is to allow CWIP in rate base.

Q. Is there a fundamental difference between the two approaches?

A. Yes, there is. Accruing AFUDC adds to the capital costs of a project. The return is an accounting entry only and is actually realized when the capital asset is included in rate base and is depreciated. Including CWIP in rate base avoids increasing the capital cost of the project through AFUDC and earns a return in rates while the project is being constructed.

Q. What are the main reasons why a CWIP project would not qualify for AFUDC?

A. There are two main reasons. First, under the Commission's AFUDC rule, if the project's construction period is less than 12 months, it does not qualify. Second, if the project is allowed in rate base, it does not qualify for AFUDC.

Q. What is witness Chriss recommending for CWIP for Tampa Electric?

A. Witness Chriss recommends that $174.1 million of CWIP be excluded from Tampa Electric's rate base and be denied a return.

Q. How is a return being denied?

A. The $174.1 million represents short-term construction projects which do not qualify for AFUDC under the Commission's rule. If these projects are not included in rate base, Tampa Electric will be denied an opportunity to earn a return on capital that it has deployed to adequately meet its customers' need for service.

Q. Witness Chriss rationalizes his recommended disallowance on the grounds that the $174.1 million is not used and useful. Do you agree?

A. No, I do not. First, it needs to be understood that an accounting classification does not mean that invested amounts are not providing benefits to customers. Customers expect and deserve to have facilities in place to serve them when needed and to modernize existing facilities when it is cost-effective and/or improves service. In fact, if Tampa Electric did not make these investments, it could be sanctioned by the Commission for not doing so.

Second, capital projects take time to construct, some longer than others. Costs are incurred to carry these projects to their ultimate completion. A project with a construction time of less than 12 months still incurs

these carrying costs and these costs should be recognized in setting rates. Not doing so would be analogous to a bank not having to pay interest on CDs of less than 12 months. Obviously, investors expect a return on capital for the entire time that it is invested, not for just when it exceeds 12 months.

Third, labeling an investment as "not used or useful" does not mean that it should automatically be excluded from rate base and denied the opportunity to earn a return. The Commission, in adopting Rule 25-6.041, F.A.C., recognizes that CWIP can be allowed in rate base. Even long-term projects that otherwise would qualify for AFUDC can be included in rate base to maintain a utility's financial integrity.

Q. How is financial integrity threatened by large amounts of CWIP?

A. A large construction program can put financial strains on a utility, even if AFUDC is allowed. AFUDC is a non-cash accounting entry with delayed realization of earnings. With insufficient cash flows, bond ratings can be threatened. In addition, denying both AFUDC and rate base inclusion, as witness Chriss suggests, would only

exacerbate potential negative financial impacts.

Q. Has the Commission allowed the inclusion in rate base of CWIP which is ineligible for AFUDC?

A. Yes, this is the Commission's established practice. The Commission has acknowledged that short-term construction projects are a necessary part of providing quality service and should be allowed in rate base as opposed to accruing AFUDC.

Q. Has the Commission ever conducted an investigation into the proper accounting and ratemaking treatment for CWIP?

A. Yes, the Commission conducted such an investigation in Docket No. 72609-PU and issued its findings in Order No. 6640, dated April 28, 1975.

Q. What were the Commission's findings?

A. The Commission reaffirmed its previous findings that there should be two (and only two) options for CWIP. The Commission stated:

> The Commission's currently prescribed

accounting treatment of AFDC was established by Order No. 3143 in Docket No. 6655 issued in 1962. It provides the companies with two options:

a. Charge AFDC on CWIP and not include CWIP in rate base.
b. Not charge AFDC and include CWIP in rate base.

Q. Did the Commission address the proper treatment of construction projects with shorter construction times?

A. Yes. The Commission did and generally referred to such projects as "blanket work orders", recognizing that such projects were generally not great in individual dollar amounts, and were routine or recurring in nature. Such projects were accounted for on a blanket work order basis.

Q. What did the Commission decide for these types of projects?

A. The Commission recognized that such projects generally do not receive AFUDC and thus should be included in rate

base. The Commission stated:

> Due to the differences in operating characteristics of the various companies, we deem it inappropriate and impractical to attempt to set a standard for the dollar amount or time span that would be used to determine the eligibility of certain construction projects as blanket work orders. However, since blanket work orders do not receive AFDC and thus are permitted under our optional provisions of being included in the rate base, we believe the levels set by the companies should be reviewed by this Commission for purposes of testing their reasonableness.
>
> It should also be emphasized that in order to be eligible for inclusion in the rate base, blanket work orders should not receive AFDC at any time, either in the past or future.

Q. Has the $174.1 million of CWIP that Tampa Electric is requesting to be included in its rate base ever accrued AFUDC?

A. No, it has not and therefore, should be included in Tampa Electric's rate base.

Q. Witness Chriss asserts that the inclusion of CWIP in rate base shifts the risks traditionally assumed by investors to ratepayers. Do you agree with his rationale?

A. I do not agree. There is no shifting of risk. Investors have put their capital at risk by investing capital in a utility and are justifiably seeking a return, either through rate base inclusion or through the accrual of AFUDC. This is standard practice and fairly compensates investors for putting their capital at risk. Ratepayers have no risk, only the obligation to fairly pay for service and adequately compensate Tampa Electric's investors.

Q. Witness Chriss further opines that any inclusion of CWIP in rate base should result in a lower authorized return on equity ("ROE") for Tampa Electric. Do you agree?

A. No, I do not. As I just stated, there is no shifting of risk by including CWIP in rate base. To the contrary, accepting witness Chriss' recommendation would result in a denial of a return on invested capital and a tremendous

shift in established regulatory policy that would upset settled expectations. This would place even greater risks on investors. Concomitantly, bondholders would demand higher interest rates and stockholders would demand a higher ROE. This is not in the customers' best interest.

RECONCILIATION OF RATE BASE AND CAPITAL STRUCTURE

Q. What is the Commission's policy regarding the reconciliation of rate base and capital structure?

A. The Commission's policy is to reconcile the amount of rate base investment with the amount and sources of capital in a utility's capital structure which are used to support the rate base investment. This results in a matching of sources and uses of capital as a basis to more accurately determine the costs of providing service and to calculate a utility's revenue requirement in a rate proceeding.

Q. How is the reconciliation accomplished?

A. It starts with the company's balance sheet taken from its books and records. The assets as shown on the balance sheet are jurisdictionalized and adjusted consistent with

regulatory policy to result in the company's rate base. The company's equity, debt, and other liabilities are then adjusted to equal the rate base. Absent extraordinary circumstances or special policy considerations, the adjustments are made on a pro rata basis over all sources of capital in the company's capital structure.

Q. Why is the allocation done on a pro rata basis?

A. There are three main reasons why it is done pro rata. First, it is generally understood in the financial community and specifically recognized within regulation that funds are fungible and cannot generally be traced from a specific source to a specific application. Second, making allocations to deferred taxes on any basis other than pro rata could have the effect of violating income tax normalization requirements and putting the deferred taxes in jeopardy. And third, pro rata is a fair and easily applied allocation methodology.

Q. What does witness Gorman recommend in regard to the reconciliation of rate base and capital structure?

A. Witness Gorman recommends that the Commission's pro rata

allocation methodology be restricted only to investor sources of capital and not applied at all to deferred taxes and customer deposits. This has the effect of over-weighting these sources of capital and inappropriately reducing Tampa Electric's overall weighted cost of capital.

Q. What is witness Gorman's rationale for making this recommendation?

A. Witness Gorman opines that the customers have provided these sources of capital and should receive the full benefit of them.

Q. Do you agree with his opinion?

A. No. His opinion that customers have provided the deferred taxes is debatable. More importantly, his opinion that customers are not receiving the "full benefit" is misplaced.

Q. What gives rise to deferred taxes?

A. Deferred taxes are an accounting entry which recognizes the difference in time between when an amount of income

tax expense is recognized on the books and when the liability arising from that expense becomes payable is actually paid to the government. The bulk of deferred taxes generally arise from differences in the amount of depreciation expense allowed as a deductible expense in the current period (accelerated depreciation) and the amount of depreciation expense actually booked as a current period expense. In this sense, the deferred taxes are an interest free loan from the government. The amount of income tax expense recognized as a recoverable expense in rates is the current period expense and reflects the current period cost of providing service. This is what customers pay. The government essentially allows a delay in the payment, which will be ultimately paid when the accelerated depreciation reverses in later years.

Q. Do customers receive the full benefit of the deferred taxes?

A. Yes, they do in two ways. First, the impact of accelerated depreciation reverses over time and customers receive the full tax benefit of the depreciation over the life of the asset pay only the amount of income tax expense that is eventually paid to the government.

Second, during the time that the deferred taxes exist on the company's books, the zero cost loan from the government is included in the company's capital structure at zero cost.

Q. Does witness Gorman's suggested reconciliation methodology result in customers receiving a full benefit of the cost savings?

A. There actually is no cost savings, just a delay in the recognition of the expense and when the associated liability comes due is paid to the government. The benefit of this delay, however, is fully recognized. In contrast, witness Gorman's approach would result in a "double benefit" to customers.

Q. How so?

A. Deferred taxes and customer deposits are sources of capital that are used to support investments across all of Tampa Electric's assets, just like equity and debt capital obtained from investors. When an asset is removed from or not allowed in rate base, witness Gorman's approach ignores this. Instead, he supports full recognition of the non-inclusion of the asset in

rate base, but ignores the deferred taxes and customer deposits which support that asset. Under his approach, customers are not required to pay for the asset and are beneficiaries of 100 percent of the deferred taxes. In this sense, there is a "double benefit" to customers.

Q. How did the Commission allocate rate base adjustments in Gulf Power Company's last rate proceeding?

A. The Commission did it pro rata for Gulf Power Company. In Order No. PSC-12-0179-FOF-EI, issued on April 3, 2012 in Docket No. 110138-EI, the Commission stated:

> We find that Gulf has reasonably relied on our previous treatment of ADITs to include in the capital structure. Additionally, in reconciling rate base and capital structure, Gulf and the other parties agree the capital structure shall be reconciled to rate base pro rata over all sources of capital. By adjusting the capital structure on a pro rata basis for the Crist Units 6 and 7 turbine upgrades, deferred taxes are increased in proportion to the percent of deferred taxes in the capital structure.

Q. Has the Commission recently expressed a concern with double counting deferred income taxes?

A. Yes, in its Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI, addressing its decision in a recent Florida Power & Light ("FPL") rate proceeding, the Commission stated:

> We are concerned that the double counting of deferred income taxes might result in a violation of tax normalization rules. Per IRC§168(i)(9), tax normalization requires any ratemaking adjustment with respect to a utility's deferred income tax reserves to be consistently applied with respect to rate base, depreciation expense, and income tax expense. Pursuant to IRC§168(f)(2), the consequence of violating the normalization method of accounting is the loss of the ability to claim accelerated depreciation for income tax purposes. Such a normalization violation would result in the loss of the ability to use accelerated tax methods of depreciation. Consistent with prior PSC orders, tax normalization rules, and as discussed in

greater detail below, FPL has properly allocated pro-rata adjustments to all sources of capital.

The Commission went on to give three reasons why it was making all allocations on a pro rata basis, citing the need to be consistent with cost recovery clause treatment, concerns over potential normalization violations, and a lack of materiality. The Commission did direct staff to conduct a generic review of its allocation policy.

Q. Did such a review take place?

A. Yes, there was a workshop conducted by staff on May 12, 2010.

Q. Was there any changes made by the Commission in its allocation methodology as a result of this workshop?

A. No, not to my knowledge.

OPERATIONS & MAINTENANCE (O&M) EXPENSES

Q. What does witness Kollen recommend in regard to Tampa Electric's O&M expenses?

A. Witness Kollen recommends substantial reductions in Tampa Electric's projected 2014 O&M expenses by two different means, a "top-down" approach and a "bottoms-up" approach. Under his top-down approach, witness Kollen recommends a disallowance of $40.898 million. Under his bottom-up approach, witness Kollen recommends a disallowance of $31.876 million.

Q. What is the basis for witness Kollen's recommended top-down disallowance?

A. Witness Kollen begins with Tampa Electric's 2012 level of jurisdictional O&M expenses of $299.546 million and increases it by a 2-year inflation factor of 4.7 percent to derive his recommended level of 2014 O&M expenses of $313.633 million. He then compares his recommended level to Tampa Electric's 2014 forecasted level of O&M expenses to result in his $40.898 million recommended disallowance.

Q. Is this approach reasonable and appropriate?

A. It is neither reasonable nor appropriate.

Q. Please explain.

A. Witness Kollen's approach is an overly simplistic analysis that cannot be relied upon to accurately establish the amount of O&M expenses necessary to provide service in 2014 and beyond. He blindly establishes 2012 as a representative year upon which mere inflation factors can be applied to establish going forward amounts. He conveniently ignores substantial testimony by Tampa Electric witnesses that 2012 is not representative of normal on-going expense levels and the substantial testimony of Tampa Electric witnesses who support the needs in the 2014 budget. His approach is similar to the Commission's O&M Benchmark and applies the result in a manner never intended. If the Commission were to accept witness Kollen's approach and the recommended disallowance resulting there from, the Commission would be abdicating its responsibility to establish expense levels reasonably necessary to provide service on a going forward basis.

Q. How is witness Kollen's top-down approach similar to the Commission's O&M Benchmark?

A. Witness Kollen's top-down approach is similar in that it takes a base year and escalates it to calculate a benchmark. However, it is also significantly different

in both its calculation and, more importantly, in its application.

Q. Please explain how it is different in its calculation.

A. The Commission's O&M Benchmark begins with the level of O&M expenses for a prior year that have been reviewed as part of a rate case. It then escalates this level of O&M expenses by both inflation and customer growth to determine the benchmark level. The analysis also calculates a benchmark by functional areas within the company. In contrast, witness Kollen's approach chooses 2012 as the base year, a non-test year that has not been determined to be reasonable, necessary and reflective of on-going needs. He then only applies an inflation factor and not a factor for customer growth. Neither does his analysis show amounts by function.

Q. Please explain how it is different in its application.

A. The Commission's O&M Benchmark is an analytical tool used by the Commission to better scrutinize expense levels and to give the company an opportunity to justify expense levels which may exceed the benchmark. The Commission has never used the Benchmark as an absolute limitation on

the amount of expense determined to be reasonable and necessary on a going forward basis. In contrast, witness Kollen uses his 2012 base year escalated by inflation as an absolute limitation. His approach effectively denies Tampa Electric the opportunity to justify the level of expense it is seeking in the 2014 test year.

Q. On what basis can a utility company justify expenses above a benchmark level?

A. It is the utility company's responsibility to justify these amounts based on its particular facts and circumstances. However, such justifications can be based on a showing that specific expenses are not well gauged by a general inflation factor or that additional expenses are reasonably necessary to meet customer expectations or to meet increased standards and requirements. For example, certain types of expenses may exceed general inflation, such as health care costs, diesel fuel for trucks and other equipment, and certain materials or components that may be subject to high demand and low supply. Examples of increased expenses due to increased requirements would be storm hardening, increased maintenance needed to meet reliability requirements, and increased outage activities needed to optimize plant

performance. Such expenses should be evaluated for reasonableness and not summarily rejected if they exceed a base amount escalated for inflation.

Q. Are there similar flaws in witness Kollen's bottoms-up approach?

A. Yes, there are. First, it should be observed that witness Kollen's bottoms-up approach attempts to look at Tampa Electric's O&M expenses with greater granularity and the result is a reduced recommended disallowance, i.e., $31.876 versus $40.898 million. This highlights the fact that witness Kollen's top-down approach cannot be relied upon to yield meaningful results. Nevertheless, some of witness Kollen's recommended disallowances included in his bottoms-up approach contain the same or similar flawed premise as contained in his top-down approach.

Q. What is this flawed premise?

A. The flawed premise is that a prior year escalated for inflation or that an average of a series of prior years without escalation for inflation should be used as a limitation on the amount of expenses allowed as

reasonable in the 2014 test year. As used in his top-down approach, witness Kollen escalates Tampa Electric's 2012 distribution O&M expense by inflation to set a limitation on allowable distribution O&M expense, resulting in a recommended disallowance of $5.317 million. Witness Kollen slightly changes his approach for planned maintenance outage expense. Instead of escalating 2012 for inflation, he averages the years 2010 - 2012, without escalation for inflation, to calculate his limitation on allowable planned maintenance outage expense. This approach results in his recommended disallowance of $7.145 million. It is interesting to note that had witness Kollen continued to use the approach wherein 2012 is escalated for inflation, his recommended disallowance for planned maintenance outage expense would have been approximately $800,000 lower.

Q. What is your recommendation for Tampa Electric's allowable level of O&M expenses?

A. I do not have a quantified dollar recommendation. My recommendation is to reject witness Kollen's reliance on a benchmark type approach to place limitations on what otherwise may be necessary and reasonable expense levels. The Commission should continue its practice of using its

O&M Benchmark to scrutinize expenses and consider Tampa Electric's justifications for its 2014 projected expense levels. The goal is to set 2014 expense levels that are reasonable and necessary to provide safe, efficient, and reliable service on a going forward basis.

Q. What consideration do you believe should be given to the level of O&M expenses incurred by Tampa Electric in 2011 and 2012?

A. I think the commission should consider those expense levels as it evaluates the company's proposed level of O&M expenses in the 2014 test year, but should keep those three historical years in perspective. Several of the company's witnesses have explained that the company's revenues for 2011 and 2012 were much lower than anticipated due to weather, economic conditions and changes in customer usage patterns. The company responded to these unexpected changes by taking extraordinary steps to reduce O&M expenses to maintain the financial health of the company. I would encourage the commission to evaluate the company's levels of O&M spending in light of what was happening to the company in those years and to refrain from adjusting test year O&M expenses based on comparisons to 2011 and 2012 or

averages using those years. The commission would likely be reluctant to use years with higher than normal O&M expenses as a touch point for evaluating test year expenses, and it should be equally reluctant to evaluate test year expenses against years when spending was cut to austere "just get by" levels. The commission's goal should be to approve a sustainable level of O&M spending that will allow the company to provide reasonable and reliable service to its customers. Holding the company to unusually low levels achieved during extreme conditions in some sense amounts to "no good deed going unpunished" and is not in the best long run interests of the customers.

EQUITY RATIO

Q. Does witness Kollen make a recommendation to incentivize Tampa Electric to reduce its equity ratio?

A. Yes, witness Kollen presents two options. His first option is to reduce the equity ratio in this case and to allow 25 percent of the revenue requirement reduction to be added to Tampa Electric's Performance Sharing Plan ("PSP") incentive compensation expense. His second option is to have Tampa Electric reduce its equity ratio in its next rate case, with the understanding that the

Commission would allow a pro forma adjustment in the next case to increase PSP incentive compensation expense by 25 percent of the lower revenue requirement.

Q. Should the Commission accept either of these options?

A. No, the Commission should reject both options. Both are based on a premise that is unsubstantiated and both constitute bad regulatory policy.

Q. How is the premise for these options unsubstantiated?

A. Witness Kollen's premise is that Tampa Electric's current equity ratio is excessive and that a lower equity ratio would reduce Tampa Electric's revenue requirement. Other than referencing witness Baudino's position that Tampa Electric's equity ratio is higher than witness Baudino's comparative group, witness Kollen does not show that Tampa Electric's equity ratio is excessive. The appropriateness of Tampa Electric's equity ratio should be evaluated on Tampa Electric's specific facts and circumstances, such as its overall risk profile and its ability to obtain capital on reasonable terms. It is also unsubstantiated that a lower equity ratio would reduce Tampa Electric's revenue requirement. It is

mathematically true that, assuming everything else is equal, a lower equity ratio lowers revenue requirements. However, making such a naïve assumption is not indicative of the real world where revenue requirements are intertwined with a myriad of different factors moving the calculation of revenue requirements in opposite directions. The goal should be a balanced equity ratio that optimizes risk mitigation and revenue requirements. A company's equity ratio is a financial metric closely watched and evaluated by financial analysts. As such, it should not be changed unless there is a compelling reason to do so.

Q. How do witness Kollen's options constitute bad regulatory policy?

A. Both of witness Kollen's options break from the principle that incentives should be implemented to encourage actions that produce mutual benefit. Incentives should not be used to incent actions that do not have a clear mutual benefit or encourage conflicting actions. His options place Tampa Electric's management in an untenable position of choosing between an equity ratio that it believes is appropriate and financial gain for its managers and employees. Furthermore, Tampa Electric's

overall compensation program, including PSP, should be set at a level to attract, retain, and motivate employees. To achieve this goal, Tampa Electric targets its overall compensation at the market median. Allowing additional PSP compensation as an incentive could result in excessive compensation.

AMORTIZATION OF SOFTWARE

Q. What does witness Pous recommend for the amortization of software costs?

A. Witness Pous is recommending two separate adjustments. First, he recommends that Tampa Electric's 10 year amortization period be increased to 15 years. Second, he recommends that the historical accumulated amortization reserve be restated (increased) to reflect a 5 year amortization. Witness Pous' recommendations are inconsistent with goals of regulation and are internally inconsistent in rationale and application. The only way they are consistent is that they both inappropriately reduce Tampa Electric's revenue requirements in the current rate case.

Q. How are witness Pous' recommendations inconsistent with goals of regulation?

A. An important goal of regulation is to objectively set amortization rates which best match the amortization period with the expected life of the intangible asset being amortized. This should be done without consideration of whether a change in amortization would affect customer rates (either up or down) in a rate case. Witness Pous' recommendations to restate the amortization reserve and to increase the amortization period going forward appear to be driven by the inappropriate goal of minimizing revenue requirements in the current rate case.

Another goal of regulation is to not only objectively match the amortization period of an intangible asset with its expected life, but also have the annual amortization expense be as consistent and smooth as possible. Specifically in regard to Tampa Electric's Enterprise Resource Planning ("ERP") software, witness Pous' recommendation would have the amortization heavily skewed to the early years of the software's deployment and then greatly diminished over the remaining years of his recommended 15 year life. In contrast, Tampa Electric's proposed amortization would be 10 percent per year over the asset's 10 year expected life. This is graphically depicted for a hypothetical in my Document 3 of my exhibit.

Q. Do you have a position on the appropriateness of a 10 year amortization versus a 15 year amortization?

A. No, I have no position on which amortization period is more appropriate. As I stated earlier, the amortization period should match the expected life of the intangible asset as closely as possible. However, I do have two observations. First, regardless of whether the expected life is 10 years or 15 years, it is obvious that it is not expected to be 5 years and that Tampa Electric was justified to use a longer than 5 year period to amortize the ERP software when it was first deployed. Second, if a 15 year amortization period is used and the actual life is 10, there will be a substantial unrecovered cost at the end of the asset's life. This cost would then have to be recovered by some means, effectively pushing these costs farther out into the future.

INCENTIVE COMPENSATION

Q. Do witnesses Kollen and Schultz take issue with Tampa Electric's incentive compensation programs?

A. Yes, they both address Tampa Electric's PSP and stock compensation programs and they recommend substantial disallowances for each.

Q. What is the nature of their recommended disallowances for Tampa Electric's PSP?

A. Witness Kollen makes a "bottoms-up" adjustment to Tampa Electric's 2014 O&M expenses to disallow $5.034 million of Tampa Electric's PSP expense. The basis for his adjustment ignores the operational part of Tampa Electric's PSP and limit PSP expense to only the two percent attributable to safety related goals. He once again uses 2012 as his base year and observes that only safety related payouts were made in 2012.

Witness Schultz takes a similar approach and limits PSP expense to the two percent attributable to safety related goals. He recommends a disallowance of $5.987 million attributable to Tampa Electric, in effect allowing only two percent of his recommended payroll expense as PSP. He then further disallows $1,837 of PSP allocated from Tampa Electric Energy, for a total disallowance of $7.818 million (jurisdictional). Witness Schultz also offers an alternative recommendation. In his alternative, he eliminates all of the PSP expense attributable to operational goals and then recommends that the remainder be shared equally between stockholders and customers. This results in a total recommended disallowance of

$8.074 (jurisdictional). He further observes that no operational PSP payments were made in the years 2011 and 2012.

Q. What is the nature of their recommended disallowances of Tampa Electric's stock compensation expenses?

A. Both witness Kollen and witness Schultz eliminate all of Tampa Electric's 2014 projected stock compensation expenses. Witness Kollen recommends a disallowance of $5.084 million. Witness Schultz also eliminates stock compensation expenses allocated from Tampa Electric Energy, to result in his total recommended disallowance of $9.715 million (jurisdictional).

Q. Are there any common themes in the positions of witnesses Kollen and Schultz in regard to Tampa Electric's PSP and stock compensation programs?

A. Yes, there are two major ones. First, both witness Kollen and witness Schultz put great emphasis on their observations that no operational related amounts were paid under PSP for the years 2011 and 2012. They use this as a rationale to disallow operational related PSP expense in the 2014 test year. And second, both witness

Kollen and witness Schultz believe that financial incentives benefit stockholder(s) to the detriment of customers. They conclude that the cost of such incentives should be borne by stockholder(s).

Q. Do you agree with their rationale to disallow operational related PSP expense because no such payments were made in the years 2011 and 2012?

A. No, I do not. The real issue is whether the operational goals of the PSP and the projected payouts are reasonable and part of a broader compensation plan designed to adequately compensate and motivate employees. According to Tampa Electric witness Register, that is exactly what the operational goals and the associated payouts do. It is possible and perhaps likely that the years 2011 and 2012 are not good base years in which to conclude that operational PSP expense levels are not needed in 2014 and beyond. It is clear from the testimony of other Tampa Electric witnesses that the years 2011 and 2012 were in the midst of the Great Recession in which Tampa Electric was experiencing a dramatic decrease in expected revenues. This caused Tampa Electric management to reevaluate spending priorities and also caused many PSP goals to be unmet. This does not mean that the goals and

the expected PSP expenses are unreasonable for 2014 and beyond. This simply recognizes that under an at-risk performance pay plan, some years will see actual payouts less than budgeted and in some years greater than budgeted. It is the nature of employees having part of their compensation at risk.

Q. Do you agree with witnesses Kollen and Schultz that financial incentives benefit stockholder(s) to the detriment of customers?

A. No, I do not. Financial goals also benefit customers. Regulated utilities are profit making entities (hopefully) and must make a reasonable profit to be sustainable and to access capital when needed and on reasonable terms. This is the means by which customers receive the service that they expect and deserve. A utility earning a reasonable profit is beneficial for both its shareholders and its customers. Therefore, financial goals used to establish compensation levels are also beneficial to customers.

Q. Can you give specific examples of how financial goals benefit customers?

A. Yes, I can. Return on equity ("ROE") is a fundamental

measure of financial performance. It represents the earnings (revenues less expenses) as a percentage of equity investment. It can be increased (or its erosion diminished over time) in a number of ways. First, revenues can be increased by serving more customers with the same amount of expenses and investment. Second, expenses can be reduced by serving existing and future customers more efficiently. Third, assets can be utilized more efficiently so that the denominator in the equation (equity capital) is minimized for each dollar of income that is generated. Each of these scenarios (or a combination of them) will increase the ROE and provide added value to customers by increasing the efficiency of utility operations. This is particularly meaningful for regulated utilities which must keep rates fixed in between rate cases.

Q. Is it appropriate to allow recovery of at risk compensation based on the achievement of financial goals?

A. Yes, it is. Apparently witness Kollen also agrees with this concept. In his recommendation to achieve a reduction in Tampa Electric's equity ratio, witness Kollen recommends the awarding of greater PSP payments. Of course, as I described earlier, the financial goal of

reducing Tampa Electric's equity ratio is misguided and should not be used to award PSP payments.

Q. Should the Commission require a sharing of incentive compensation between customers and stockholder(s) as suggested by witness Schultz in his alternative position?

A. No. The suggestion to share the cost of incentive compensation is misplaced and shifts the true focus of determining the level of compensation expense (or any expense) that should be recovered in rates. A fundamental tenet of sound regulatory policy is to provide recovery of all reasonable and necessary costs incurred to provide service to customers. And a basic principle of ratemaking is to include all such costs as test year expenses in calculating a regulated company's net operating income. Only if the Commission finds that the expenses in question are unreasonable or unnecessary should they be disallowed in calculating the company's revenue requirement.

Another fundamental tenet of sound regulatory policy is to encourage regulated utilities to be efficient and provide high quality service to their customers over the long term. Sacrificing efficiency or quality of service

in the long run to achieve temporary rate reductions is not in the customers' interest. All regulatory decisions have consequences and good regulatory policy results when these consequences are adequately considered. The recommendations of witnesses Kollen and Schultz violate both of these tenets of sound regulatory policy.

Q. Please explain how their recommendations violate the tenet of recovery of reasonable and necessary costs.

A. Neither witness Kollen nor witness Schultz has presented an analysis of the employment market to determine what amount of compensation is reasonable and necessary to attract the workforce needed to efficiently and reliably run an electric utility. This is in contrast to the testimony of Tampa Electric's witness Register who explains that the overall compensation is reasonable, that it is necessary to attract and retain a qualified workforce, and that it is at or near the median of employee compensation paid by other regulated utilities.

Witness Kollen's and witness Schultz's recommendations are further flawed because they make no analysis of the reasonableness of the net amount of compensation that remains after operational PSP and stock compensation are

eliminated. They have not provided any evidence that shows the level of compensation that remains will ensure that Tampa Electric is competitive in the market in terms of its ability to attract and retain qualified employees.

Q. Has the Commission addressed incentive compensation for other Florida utilities?

A. Yes. A prior Florida Power Corporation rate case also provided for cost recovery of incentive compensation finding that: "Incentive plans that are tied to achievement of corporate goals are appropriate and provide an incentive to control costs." Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI, In Re: Petition for a rate increase by Florida Power Corporation. And in a Tampa Electric's last rate case, the Commission found that Tampa Electric's total compensation package, including the component contingent on achieving incentive goals, was set near the median level of benchmarked compensation and allowed recovery of incentive compensation that was directly tied to results of Tampa Electric:

> Tampa Electric's Success Sharing Plan has been in place since 1990 and its appropriateness was

> approved in the company's last rate case in 1992. Lowering or eliminating the incentive compensation would mean Tampa Electric employees would be compensated below the employees at other Companies, which would adversely affect the company's ability to compete in attracting and retaining a high quality and skilled workforce. We therefore decline to do so.

Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for a rate increase by Tampa Electric Company.

The Commission has also approved incentive compensation in three prior rate cases for Gulf, the most recent of which resulted in an order issued in April of last year. Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 110138-EI, In re: Petition for increase in rates by Gulf Power Company. The Commission's finding in the 2001 Gulf rate case contains language similar to the Tampa Electric case:

> To only receive a base salary would mean Gulf employees would be compensated at a lower level than employees at other companies. Therefore,

> an incentive pay plan is necessary for Gulf salaries to be competitive in the market. Another benefit of the plan is that 25 percent of an individual employee's salary must be re-earned each year. Therefore, each employee must excel to achieve a higher salary. When employees excel, we believe that the customers benefit from a higher quality of service.

Order No. PSC-02-0787-FOF-EI, in Docket 010949-EI, In re: Request for rate increase by Gulf Power Company, (page 45 of order).

Q. Are there any Florida Court decisions relevant to the issue of Commission disallowance of compensation expenses?

A. Yes, two cases are instructive in this regard and both dealt with the Commission's disallowance of executive compensation.

In Florida Bridge Company v. Bevis, the Florida Supreme Court reversed a decision of the Commission disallowing a portion of the company president's salary. The Court observed:

> Indeed, the Commission has made no attempt to determine whether the president's compensation is excessive in view of the services he provides. The arbitrary ratio by which the Commission reduced the salary and expense account[,] the ratio of days physically absent from the home office to the total number of workdays in the test year[,] has no support in logic, precedent, or policy.

363 So. 2d 799, 800-01 (Fla. 1978)

The Court found the Commission's action "was arbitrary and constitutes a substantial departure from the essential requirements of law." Id.

The First District Court of Appeal reached a similar conclusion in Sunshine Utilities of Central Florida, Inc. v. Florida Public Service Commission, in finding fault with the Commission's disallowance of a portion of the company president's salary:

> In determining whether an executive's salary is reasonable compared to salaries paid to other company executives, the comparison must, at a minimum, be based on a showing of similar

duties, activities, and responsibilities in the person receiving the salary.

624 So. 2d 306, 311 (Fla. 1st DCA 1993)

Q. How are these cases related to the disallowance of incentive compensation recommended by witnesses Kollen and Schultz?

A. It relates to the point I made earlier in my testimony regarding their failure to determine whether overall compensation expense is reasonable and necessary. The Florida Supreme Court and the First District Court of Appeal reversed the Commission's decision because the basis for the disallowances did not address the reasonableness of the salaries as compared to the market.

Witness Kollen's and witness Schultz's analyses are similarly flawed because they have made no attempt to compare the total compensation paid to Tampa Electric employees to the market for similar services, duties, activities and responsibilities. Instead they recommend a portion be disallowed based on how it is paid: Because it is performance-based variable pay, rather than base salary, it is subject to disallowance notwithstanding whether the total amount of compensation is reasonable.

The focus of any disallowance should be how much is paid, not how it is paid.

Q. How do witness Kollen's and witness Schultz's recommendations fail to encourage efficiency or maintain or improve the quality of service?

A. Their recommendations would have longer term consequences that could affect efficiency and service, and their recommendations take away a valuable managerial tool that is effective in increasing efficiency and maintaining or improving the quality of service provided to customers.

Q. What do you mean by "takes away a managerial tool"?

A. Accepting witness Kollen's and witness Schultz's recommendations would, by necessity, cause Tampa Electric to rethink its long standing approach to employee compensation. If a significant amount of otherwise valid and reasonable costs are disallowed simply because of the method by which they are paid, Tampa Electric would be justified in implementing a different pay structure. While accepting their recommendations would deny Tampa Electric the opportunity to recover necessary costs currently, adopting a different compensation plan with no

at-risk pay and a greater reliance on base pay would presumably eliminate the issue in future rate proceedings. But by moving more salary to base pay, employees don't have to re-earn that pay by meeting goals that typically include efficiency and service objectives. A compensation structure that pays employees regardless of performance diminishes management's leverage to motivate and focus employees on appropriate goals. In essence, the Commission would be substituting its judgment for that of Tampa Electric's management as to how best to motivate and compensate its employees. Consequently, the incentive for Tampa Electric's employees to be motivated and productive would be diminished.

Q. Is it your position that Commission precedent supports the recovery of all of the non-executive performance-based variable pay? And why has this been the precedent in Florida?

A. While the Commission reviews each utility's compensation costs on the facts unique to that utility, the Commission has consistently recognized that incentive compensation/performance-based variable pay, is an accepted and desirable way to achieve corporate goals and

to control costs for the benefit of customers. The Commission has also determined that incentive compensation is an appropriate component to include within overall compensation to judge whether the overall compensation paid to employees is reasonable.

I believe there are a number of reasons for this precedent. First, the Commission's policy is consistent with the basic tenets of sound regulatory policy that I described earlier. Second, the Commission has recognized that having good management at utilities is essential for regulators to achieve their mission of having safe, reliable and reasonably-priced service delivered to customers. The Commission has further understood that management needs sufficient tools and incentives to achieve these goals and that regulators should not attempt to "micro-manage" their regulated utilities. And third, the Commission has appropriately recognized that not all issues in a rate proceeding are a simple situation of "us vs. them", where every issue has a clear winner and a clear loser. While at-risk compensation has been and is currently being characterized as an "us vs. them" issue, in reality it is not. Incorporating performance-based variable pay as part of an overall compensation plan is a good example of a "win-win"

situation.

Q. What do you mean by a "win-win" situation?

A. Including performance-based variable pay as part of an overall compensation plan enables all stakeholders to win. Shareholders get to invest in a company with employees motivated to achieve appropriate corporate goals. Management gets to apply compensation tools that they think are best to motivate and fairly compensate employees. And most importantly, customers get to pay no more than a reasonable amount in their rates but get a work force that is motivated to be efficient, to reduce costs where possible and to maintain a high level of safe and reliable service.

Q. Witness Deason, do you understand that witness Schultz is not recommending that Tampa Electric not pay the entire non-executive performance-based variable pay; he is simply recommending that a portion not be recovered in rates?

A. Yes, I understand his recommendation. However, disallowing a reasonable and necessary business expense, or requiring the company to share part of the expense, is

nothing more than a backdoor approach to reducing the allowed ROE. Funds that should go to shareholders as a fair return on investment instead would be diverted to cover costs that should otherwise be recovered in rates.

DIRECTORS AND OFFICERS LIABILITY INSURANCE

Q. What is the recommendation made by witness Schultz regarding Directors and Officers Liability ("DOL") Insurance?

A. Witness Schultz is recommending the disallowance of $398,974 (jurisdictional) or 50 percent of the cost of DOL insurance premiums.

Q. Do you agree with this recommendation?

A. No, I do not.

Q. Why not?

A. I disagree for reasons similar to the points I made with regard to at-risk incentive compensation. The amount requested by Tampa Electric for DOL insurance is reasonable and is an ordinary and necessary cost of doing business, and as such the entire amount should be

recovered in rates.

Q. Why are DOL insurance premiums a necessary and reasonable cost of doing business?

A. DOL insurance is necessary to attract and retain knowledgeable, experienced and capable directors and officers. DOL insurance is purchased for the purpose of protecting the company and its directors and officers from normal risks associated with managing the company. Qualified and capable directors and officers would be reluctant to assume the responsibilities of managing a company without the assurance that their personal assets would be shielded from legal expenses, settlements or judgments arising from lawsuits. The assets of the company are likewise protected from lawsuits that could divert capital to cover any losses. Increasing scrutiny of corporate governance and the related risk exposure of directors and officers make DOL insurance a necessity in maintaining a high quality board and senior management team. Adequate liability coverage gives directors and officers the level of comfort necessary to enable them to make forward-looking decisions that will provide operational and cost-efficiency benefits for customers.

Q. Has the Commission previously addressed the need for DOL insurance?

A. Yes. The Commission's rationale in the People's Gas case and in the last Tampa Electric rate case are instructive regarding the need for DOL insurance:

> DOL Insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers without it. Moreover, ratepayers receive benefits from being part of a large public company, including, among other things, access to capital. In addition, DOL Insurance is necessary to protect the ratepayers from allegations of corporate misdeeds.

Order No. PSC-09-0411-FOF-GU, page 37 issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by People's Gas System.

> We find that DOL insurance is a part of doing business for a publicly-owned company. It is necessary to attract and retain competent

> directors and officers. Corporate surveys indicate that virtually all public entities maintain DOL insurance, including investor-owned electric utilities.

Order No. PSC-09-0283-FOF-EI, page 64 issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric company.

Q. The Peoples Gas decision references benefits to ratepayers from a large publicly traded company. What is the significance of this finding?

A. This finding correctly observes that there are benefits to customers by virtue of a company being publicly traded. Publicly traded companies have reporting and corporate governance responsibilities and have access to capital from publicly traded markets. This affords protections and access to capital on reasonable terms (assuming the company's credit metrics are sufficient), which benefits customers. However, being a publicly traded company requires an objective and knowledgeable board of directors. Sufficient DOL insurance is a concomitant necessity for a publicly traded company.

Q. Does Witness Schultz claim DOL insurance is not a

necessary and reasonable expense?

A. No, not directly. He characterizes the customer benefits from DOL insurance as being "subjective" and that DOL insurance primarily benefits shareholders.

Q. Do you agree with his characterization?

A. No, I do not. DOL insurance is not designed to benefit shareholders. DOL insurance is designed to protect the officers and directors of the corporation from lawsuits alleging harm from decisions of the officers and directors acting in their official capacity. This is an important distinction for two reasons. First, without adequate DOL insurance, any corporation would find it difficult to attract the best qualified individuals to serve as officers and directors. Second, and perhaps more importantly, it allows officers and directors to make decisions based on their best judgment and not on the goal of minimizing exposure to potential lawsuits. And this second reason is especially applicable to officers and directors of regulated utilities.

Q. Why is this second reason especially applicable to officers and directors of regulated utilities?

A. A regulated utility is in a relatively unique position as compared to typical for-profit companies. To be successful, a regulated utility must meet all of its obligations required by virtue of being a state-sanctioned regulated monopoly and must fulfill its commitments to all stakeholders, including its vendors, employees, creditors, stockholders, customers and regulators. Therefore, truly effective directors and officers must feel free to exercise their best independent judgment to balance all of those sometimes competing interests, without fear of lawsuits threatening their personal assets. It is both good public policy and good regulatory policy to encourage such informed, objective decision making that is enabled to a great extent by DOL insurance.

Q. Why is it good regulatory policy to encourage DOL insurance?

A. It is good regulatory policy to encourage DOL insurance to enable officers and directors to engage in thoughtful, objective decision making that carefully weighs the outcomes and resulting impacts on all stakeholders.

Q. Is there a real-world example of this?

A. Yes, perhaps the best example of this is the Commission's policy of encouraging settlements among the parties on matters in dispute. The best settlements are those where all parties engage in meaningful discussion and agree on sometimes significant concessions. When these concessions are believed to be in the best interest of a regulated utility and its stakeholders, the officers and directors should feel free to exercise this judgment, without the fear of a lawsuit alleging the concessions were too great.

Q. In response to a previous question, you contrasted a regulated utility with a typical for-profit company. Are for-profit companies the only entities that find it necessary and appropriate to purchase DOL insurance?

A. No, many non-profit entities purchase DOL insurance for the same reasons, i.e., to enable them to have qualified officers and directors and to enable those officers and directors to engage in objective decision making. So entities that do not even have stockholders also find it necessary and appropriate to have DOL insurance. This fact is another reason why I disagree with witness Schultz's characterization that DOL insurance is primarily to benefit shareholders.

Q. What would be the result of accepting witness Schultz's recommendation to disallow half of the cost of Tampa Electric's DOL insurance?

A. Witness Schultz characterizes his recommendation as a sharing of costs based on who he believes benefits. As I just described, I believe his opinion on who benefits is incorrect. Nevertheless, the true effect of his recommendation is to disallow one-half of the cost of Tampa Electric's DOL insurance. This is tantamount to saying that one-half of the cost is unnecessary and imprudently incurred. If this is not the effective result, his recommendation violates one of the most basic tenets of regulatory theory, i.e., that all necessary and prudent costs should be allowed to be recovered in rates.

Q. From a policy perspective, what would be the effective outcome of his recommendation?

A. His recommendation would trigger three potential outcomes, none of which is desirable for a regulated utility and its customers. First, the company could simply decide to not have DOL insurance. This would result in the extremely undesirable consequences of which I earlier spoke. Second, the company could decide to not

have DOL insurance and pay its officers and directors more to make-up for the greater risk exposure. Presumably the increased costs would then not be shared because they clearly would be prudent and necessary to attract and retain directors and officers and pay them a market level of compensation. And third, the company could retain its DOL insurance and not recover one-half of the cost of doing so.

Q. What would be the bottom-line impact of the third potential outcome?

A. Disallowing a reasonable and necessary business expense, or requiring the company to share part of the expense, is nothing more than another backdoor approach to reducing the allowed ROE. Funds that should go to shareholders as a fair return on investment instead would be diverted to cover costs that should otherwise be recovered in rates.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

DOCKET NO. 130040-EI
WITNESS: DEASON

EXHIBIT

OF

TERRY DEASON

ON BEHALF OF TAMPA ELECTRIC COMPANY

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Practice Areas:

- Energy, Telecommunications, Water and Wastewater and Public Utilities

Education:

- United States Military Academy at West Point, 1972
- Florida State University, B.S., 1975, Accounting, summa cum laude
- Florida State University, Master of Accounting, 1989

Professional Experiences:

- Radey Thomas Yon & Clark, P.A., Special Consultant, 2007 - Present
- Florida Public Service Commission, Commissioner, 1991 - 2007
- Florida Public Service Commission, Chairman, 1993 - 1995, 2000 - 2001
- Office of the Public Counsel, Chief Regulatory Analyst, 1987 - 1991
- Florida Public Service Commission, Executive Assistant to the Commissioner, 1981 - 1987
- Office of the Public Counsel, Legislative Analyst II and III, 1979 - 1981
- Ben Johnson Associates, Inc., Research Analyst, 1978 - 1979
- Office of the Public Counsel, Legislative Analyst I, 1977 - 1978
- Quincy State Bank Trust Department, Staff Accountant and Trust Assistant, 1976 - 1977

Professional Associations and Memberships:

- National Association of Regulatory Utility Commissioners (NARUC), 1993 - 1998, *Member, Executive Committee*
- National Association of Regulatory Utility Commissioners (NARUC), 1999 - 2006, *Board of Directors*

Terry Deason*

- National Association of Regulatory Utility Commissioners (NARUC), 2005-2006, *Member, Committee on Electricity*
- National Association of Regulatory Utility Commissioners (NARUC), 2004 - 2005, *Member, Committee on Telecommunications*
- National Association of Regulatory Utility Commissioners (NARUC), 1991 - 2004, *Member, Committee on Finance and Technology*
- National Association of Regulatory Utility Commissioners (NARUC), 1995 - 1998, *Member, Committee on Utility Association Oversight*
- National Association of Regulatory Utility Commissioners (NARUC) 2002 *Member, Rights-of-Way Study*
- Nuclear Waste Strategy Coalition, 2000 - 2006, *Board Member*
- Federal Energy Regulatory Commission (FERC) South Joint Board on Security Constrained Economic Dispatch, 2005 - 2006, *Member*
- Southeastern Association of Regulatory Utility Commissioners, 1991 - 2006, *Member*
- Florida Energy 20/20 Study Commission, 2000 - 2001, *Member*
- FCC Federal/State Joint Conference on Accounting, 2003 - 2005, *Member*
- Joint NARUC/Department of Energy Study Commission on Tax and Rate Treatment of Renewable Energy Projects, 1993, *Member*
- Bonbright Utilities Center at the University of Georgia, 2001, *Bonbright Distinguished Service Award Recipient*
- Eastern NARUC Utility Rate School - Faculty Member

Consulting Services and Expert Testimony Provided by Terry Deason

Regulatory and Judicial Proceedings

Prior to being appointed to the Florida Public Service Commission (Commission) Mr. Deason was an analyst with the Florida Office of Public Counsel, and testified as an expert witness before the Commission on numerous occasions in cases involving electric utilities, telecommunications companies, and water and wastewater companies. This testimony addressed ratemaking principles, including determinations of rate base, capital structure, revenue requirements, working capital allowances, and acquisition adjustments.

After retiring from the Commission, Mr. Deason has testified as an expert witness before the Commission in the following dockets:

- Docket No: 080677-EI, *Petition for Rate Increase by Florida Power & Light Company* (FPL). Mr. Deason addressed the appropriate regulatory policy and ratemaking treatment of a theoretical depreciation surplus, the critical role of subsequent year adjustments, the proper equity ratio for FPL, the Generation Base Rate Adjustment, incentive compensation, and the benefits of a regulatory approach that recognizes and rewards superior performance.

- Docket No. 110009-EI, *Nuclear Cost Recovery*. Mr. Deason addressed the appropriate use of a cumulative present value of revenue requirements analysis to evaluate the cost effectiveness of extended power uprate projects being constructed at FPL's existing nuclear power plants and the prudence of an expedited schedule adopted for construction of those projects.

- Docket No. 110138-EI, *Petition for a Rate Increase by Gulf Power Company*. Mr. Deason addressed the appropriate regulatory policy and ratemaking treatment for at-risk compensation, supplemental pension expense, directors and officers liability insurance, imputed revenues from affiliated companies, storm damage accruals, construction work in progress, operations & maintenance expense benchmark analyses, and customer impacts. Mr. Deason also filed supplemental testimony in this same docket in which he addressed the proper ratemaking treatment for Gulf Power's Crist Unit 6 and Unit 7 turbine upgrades.

- Docket No. 120009-EI, *Nuclear Cost Recovery*. Mr. Deason addressed Florida's policy to promote nuclear generation and the appropriate standards to be used in determining costs eligible for cost recovery. Mr. Deason also addressed recommendations contained in the *Commission Staff Review of Project Management Internal Controls.*

- Docket No. 120015-EI, *Petition for Rate Increase by Florida Power & Light Company* (FPL). Mr. Deason addressed the appropriate regulatory policy and ratemaking treatment for property held for future use, working capital allowances, incentive

compensation, and directors' and officers' liability insurance, and FPL's requested return on equity performance adder. In this same docket, Mr. Deason provided testimony addressing a proposed settlement agreement and issues of cost-based rates, a proposed Generating Base Rate Adjustment mechanism, the use of discretionary amortizations to FPL's fossil dismantlement reserve, and the appropriate regulatory context for the Commission to consider a proposed settlement.

- Docket No. 090538-TP, *Amended Complaint of Qwest Communications Company, LLC.* Mr. Deason responded to assertions that there had been rate discrimination in connection with the provisioning of intrastate switched access service by certain competitive local exchange companies in Florida. As part of his testimony, Mr. Deason explained the historical regulatory policies and ratemaking treatment for telecommunications companies in Florida and the transition to a competitive market.

In addition to consulting and expert testimony provided by Mr. Deason in regulatory proceedings in Florida, Mr. Deason's experience includes:

- Testimony on behalf of the North Dakota Public Service Commission (NDPSC) in Case Nos. PU-06-481 and PU-06-482 regarding the Advance Prudence Determination for Big Stone II, a super-critical pulverized coal unit to be constructed by Otter Tail Power Company and Montana-Dakota Utilities Company. Mr. Deason was retained by the NDPSC to review the applicants' case, conduct discovery, prepare and present testimony with his independent recommendations, and to otherwise assist the NDPSC advocacy staff in processing the case..

- Testimony on behalf of Entergy Arkansas, Inc., The Empire District Electric Company, Oklahoma Gas and Electric Company, and Southwestern Electric Power Company in Docket No. 08-090-U before the Arkansas Public Service Commission (APSC). Mr. Deason made an independent review of a storm cost recovery mechanism filed before the APSC. Mr. Deason's testimony relied on his experience with storm cost recovery in Florida and was supportive of the mechanism filed with the APSC.

- Testimony on behalf of NorthWestern Energy in Docket No. 2008.6.69 before the Montana Public Service Commission (MPSC). Mr. Deason addressed the appropriate regulatory treatment for income taxes when a regulated utility participates in a consolidated tax return with unregulated affiliates that have incurred net operating losses (NOLs). The case involved an application to include a previously unregulated generating unit in Northwestern's regulated rate base under certain terms and conditions. One of the conditions was to have the plant included at market value with no diminution from consolidated NOLs. Mr. Deason's testimony supported this position as part of the utility's overall application.

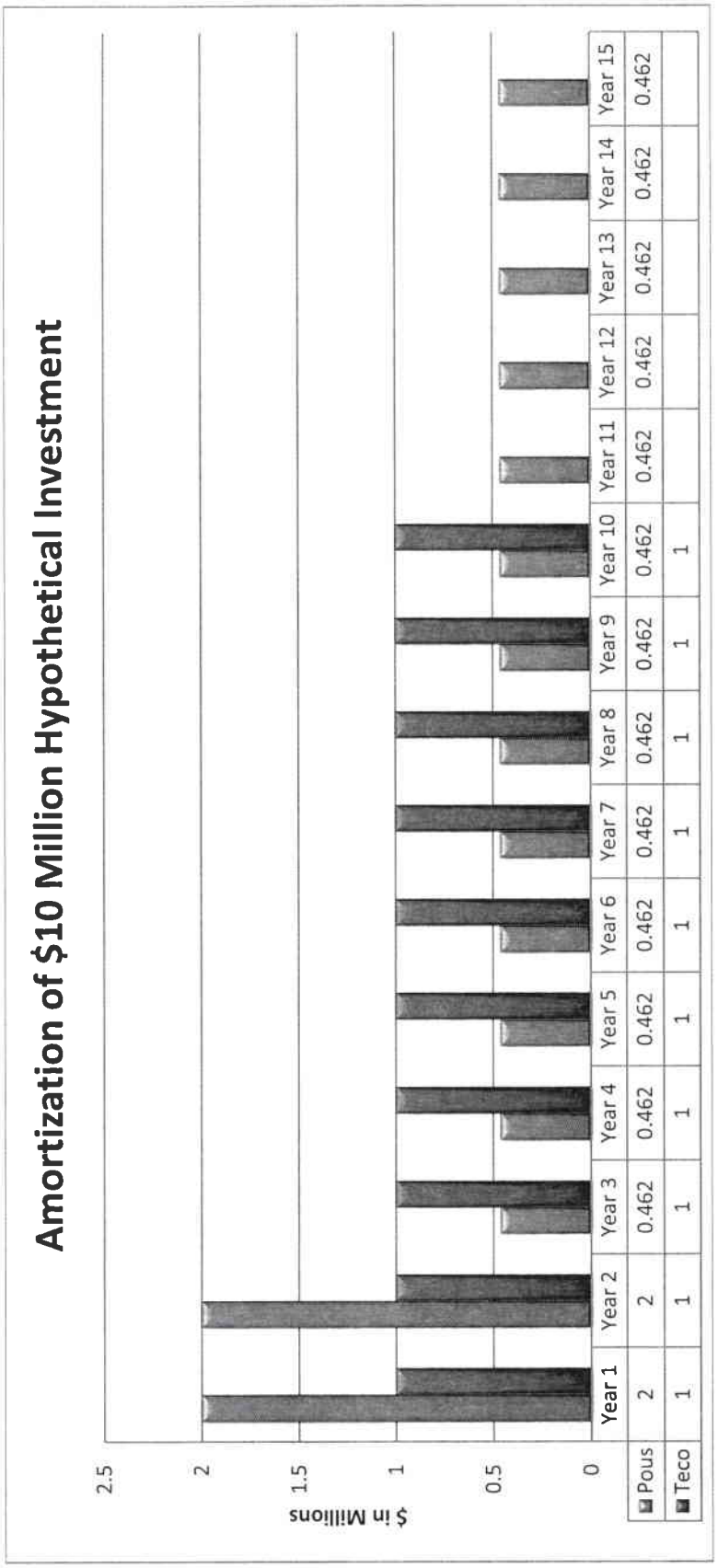
- Affidavit filed on behalf of the Consolidated Edison Company of New York, Inc. before the New York Public Service Commission (NYPSC) in Case No. 08-E-0539. As part of a

Petition for Rehearing, Mr. Deason addressed regulatory policy principles in general and how those principles should be applied to determine the appropriateness of an austerity adjustment ordered by the NYPSC.

- Expert Report filed in Case No. 11-198CA before The Circuit Court of the Fourteenth Judicial Circuit of Florida on behalf of Florida Public Utilities Company (FPUC) in a suit by the City of Marianna alleging breach of a franchise agreement. Mr. Deason addressed the appropriate regulatory basis for setting cost-based rates in Florida. Mr. Deason further addressed the appropriateness of Time of Use and Interruptible Service rates being based on a discount negotiated from FPUC's wholesale energy provider.

Legislative Testimony and Industry Presentations

Mr. Deason has given testimony as an energy policy expert before the Florida Legislature and the Florida Energy and Climate Commission on regulatory policy concerning renewable energy, cost-effectiveness determinations for Demand Side Management and conservation programs, and reliability concerns for the electric grid in Florida. Mr. Deason has also been active in giving speeches and expert presentations on energy related issues. For example, Mr. Deason made a presentation on nuclear energy issues at a conference sponsored by the Utah Department of Economic Development, made a presentation of fuel diversity at the 2012 Florida Energy Summit, and has given speeches before the NCCI Coal Institute, the Rate and Regulatory Affairs Committee of the Edison Electric Institute, and at the Nuclear Energy Institute's Conference on Communicating Nuclear Issues.



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