COMMONWEALTH OF KENTUCKY

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PUBLIC SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION FOR A GENERAL	)	
ADJUSTMENT OF ELECTRIC RATES	)	Case No. 2013-00197
OF KENTUCKY POWER COMPANY	)	

SECTION VI

DIRECT TESTIMONY OF

PAULEY, AVERA, BARTSCH, BUCK AND CARLIN

ON BEHALF OF KENTUCKY POWER COMPANY

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION FOR A GENERAL	)	
ADJUSTMENT OF ELECTRIC RATES	)	Case No. 2013-00197
OF KENTUCKY POWER COMPANY	)	

DIRECT TESTIMONY OF

GREGORY G. PAULEY

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
GREGORY G. PAULEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00197

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VERIFICATION

The undersigned Gregory G. Pauley, being duly sworn, deposes and says he is the President and COO of Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Gregory G. Pauley

Gregory G. Pauley

COMMONWEALTH OF KENTUCKY)
) Case No. 2013-00197
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory G. Pauley, this the 18th day of June 2013.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

DIRECT TESTIMONY OF
GREGORY G. PAULEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Gregory G. Pauley. My position is President and Chief Operating Officer ("COO"), Kentucky Power Company ("Kentucky Power" or the "Company.") My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40601.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor's degree from Harding University in May 1973. I also graduated from management development programs at The Ohio State University and Virginia Polytechnic Institute and State University. I currently serve as President and COO of Kentucky Power (2010). From 2006-2010 I was Director – Public Policy for American Electric Power Service Corporation ("AEPSC") working on policy issues affecting the utility industry on a national level. Prior to that, I served as Kentucky Power's Governmental/Environmental Affairs manager from 2001-2006. I have also held positions at other American Electric Power Company, Inc. ("AEP") operating units in community affairs, manager of distribution services, human resources and accounting at various operations and generation facilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided supplemental testimony and testified in Case No. 2011-00042, *In the Matter of: The Application of AEP Kentucky Transmission Company, Inc. For A Certificate Of Public Convenience And Necessity To Operate As A Transmission Only Public Utility.* I also provided direct and rebuttal testimony in Case No. 2012-00578 regarding the Company's proposed transfer of an undivided 50% interest in the Mitchell Generating Station.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony in this proceeding is to provide an overview of the Company and its request to set retail rates that will provide an additional $113,998,826 in annual revenue. I will also introduce the witnesses that will provide testimony in this case in support of the Company's requested rate changes.

IV. OVERVIEW OF KENTUCKY POWER'S APPLICATION

Q. PLEASE GIVE A BRIEF OVERVIEW OF THE COMPANY AND ITS OPERATIONS.

A. Kentucky Power is a wholly owned subsidiary of AEP and is engaged in the generation, purchase, transmission and distribution of electric power. The Company serves approximately 173,000 retail customers located in 20 eastern Kentucky counties. These customers are served through our distribution operations headquarters in Ashland, Kentucky (Cannonsburg), with satellite service centers in Hazard and Pikeville. The Company also sells electric power at wholesale rates to the City of Olive Hill and the City of Vanceburg. Exhibit GGP-1 is a map detailing the Company's service territory in Kentucky. The Company maintains a state office in Frankfort, Kentucky, which houses the office of president, governmental/environmental affairs, corporate communications, business operations support and regulatory affairs. The Company supports the communities we serve through employee involvement and corporate contributions to organization that promote community economic growth and education.

Q. WHAT ARE THE PRINCIPLE REASONS KENTUCKY POWER IS SEEKING TO ADJUST ITS RATES?

A. Because of cumulative structural and regulatory developments affecting the electric utility industry, Kentucky Power has been forced to undertake significant changes in the manner in which it serves its customers. Two of these changes drive the need for the Company's requested rate change. First, effective January 1, 2014 the Interconnection Agreement among the AEP-East Operating Companies ("Pool Agreement") will terminate. With the termination of the Pool Agreement, the Company will be responsible for meeting its capacity and energy obligations as a stand-alone company without being able to rely on the other members of the Pool. The Pool Agreement has been in place for over 50 years and its termination mandates a change to the way the Company's rates are calculated.

Second, and most importantly, emerging environmental regulations, in particular the mercury and air toxics rule ("MATS") promulgated by the United States

Environmental Protection Agency under the Clean Air Act, forced Kentucky Power to reevaluate its generation portfolio. Under MATS, the Company would be prohibited from operating the generating units at its Big Sandy Plant without extensive retrofitting, refueling or repowering beyond the June 2015. Following extensive evaluation of reasonable alternatives (including the installation of a dry flue gas desulfurization unit at Big Sandy Unit 2), the Company concluded that the transfer of an undivided 50% interest in Ohio Power's Mitchell Generating Station represents the least-cost alternative to meet its customers' needs. Kentucky Power has sought approval of this transfer in Case No. 2012-00578. If approved, the transfer of the 50% interest in the Mitchell units will occur on December 31, 2013 allowing for an overlap period prior to the planned retirement of Big Sandy Unit 2 at the end of May 2015. The inclusion of the Mitchell units during this overlap period is the primary driver of the proposed rate change.

Q. WOULD YOU PROVIDE A BRIEF OVERVIEW OF THE FILING?

A. Kentucky Power is seeking approval of a change in its retail rates that will provide an additional $113,998,826 in annual revenue, an increase of 23.39% over its current revenue requirement. This increase is based on adjusted data for the historic test year ending March 31, 2013 and known and measurable adjustments to that data to present a more accurate picture of the Company's data going forward. The major components of the requested rate change which are detailed in the testimonies of the other witnesses include:

- An adjustment of the Company's rates to reflect transfer of an undivided 50% interest in the Mitchell Generating Station on December 31, 2013;

- Changes to the Off-System Sales Tracker;
- Modified Depreciation Rates and Annualization;
- An increase in the Company's operating expenses since the Company's last general adjustment in rates; and
- Return on Common Equity of 10.65%.

Q. **WHAT TESTIMONY IS BEING FILED BY KENTUCKY POWER IN SUPPORT OF ITS APPLICATION?**

A. The Company's proposed changes in annual revenue requirement as well as the adjustments to test year revenues, operating expenses, rate base and capitalization are sponsored by the following witnesses:

WITNESS	SUBJECT AREA
William E. Avera	Cost of Equity/Return on Equity
Jeffrey B. Bartsch	Taxes and Certain Adjustments
Douglas R. Buck	Rate Design
Andrew R. Carlin	Employee Compensation
David A. Davis	Depreciation Study
Hugh E. McCoy	Pension Plan Costs
John M. McManus	Environmental Issues
Thomas E. Mitchell	Accounting Issues and Amortization for Certain Adjustment
Lila P. Munsey	Cost Allocation to Kentucky Retail Customers; Environmental Surcharge Revisions; Revenue and Operation Expense Adjustments; Tariff Revisions
Marc D. Reitter	Cost of Capital; Post Mitchell Transfer Capital Structure
Jason M. Stegall	Revenue Adjustments; Class Cost of Service Study; Revenue Adjustments
Alex E. Vaughn	PJM Rider; Transmission Function Revenues and Expenses; Certain Adjustments as a Result of the Termination of the AEP East Pool; Mitchell Cost of Service Allocation (per books)
Ranie K. Wohnhas	Proposed Increase in Annual Revenues; Tariff Revisions, Capitalization Adjustments; Big Sandy O&M and Depreciation Expense Amortization; Amortization

WITNESS	SUBJECT AREA
	of Regulatory Assets and Deferred Costs; Revenue and Operating Expense Adjustments

Q. ARE THE RATES REQUESTED BY KENTUCKY POWER FAIR, JUST AND REASONABLE?

A. Yes. Kentucky Power's goal is to provide reliable and cost-effective service to its customers while also producing a reasonable return for its shareholders. The fundamental changes facing the electric utility industry, primarily in the form of evolving and stricter environmental regulations, have forced Kentucky Power to reevaluate its generation portfolio. Through this evaluation, the Company has concluded that the transfer of 50% of the Mitchell units represents the lowest-cost, least risk alternative to meet its customers' needs. This change in the generation portfolio necessitates a change in the Company's annual revenue requirement. Kentucky Power's proposed rate changes represent fair, just and reasonable rates that will allow it to continue to provide the service that customers require and the earnings that the Company's shareholders deserve.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION FOR A GENERAL	**)**
ADJUSTMENT OF ELECTRIC RATES	**) Case No. 2013-00197**
OF KENTUCKY POWER COMPANY	**)**

DIRECT TESTIMONY OF

WILLIAM E. AVERA

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

Dr. William E. Avera being duly sworn deposes and says he is the President of FINCAP, Inc., and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

William E. Avera

DR. WILLIAM E. AVERA

STATE OF TEXAS)
) CASE NO. 2013-00197
COUNTY OF TRAVIS)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Dr. William E. Avera this 18th day of June 2013.

Notary Public

My Commission Expires: 1/10/15

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm. Exp. Jan. 10, 2015

DIRECT TESTIMONY OF
WILLIAM E. AVERA, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00197

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DIRECT TESTIMONY OF
WILLIAM E. AVERA, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a principal in Financial Concepts and Applications, Inc. (FINCAP), a firm engaged in financial, economic, and policy consulting to business and government.

A. Qualifications

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

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

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states, including the Kentucky Public Service Commission ("Commission").

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

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

Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit WEA-1.

B. <u>Overview</u>

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

A. The purpose of my testimony is to present to the Commission my independent assessment of the fair rate of return on equity ("ROE") that Kentucky Power Company ("Kentucky Power" or "the Company") should be authorized to earn on its investment in providing electric utility service. In addition, I also examined the reasonableness of Kentucky Power's equity ratio, considering both the specific risks faced by the Company, as well as other industry guidelines.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to Kentucky Power and its parent company, American Electric Power Company, Inc. ("AEP"). I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for Kentucky Power, and they form the basis of my analyses and conclusions.

Q. WHAT IS THE ROLE OF THE ROE IN SETTING UTILITY RATES?

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

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. After first summarizing my conclusions and recommendations, I reviewed current conditions in the capital markets and their implications in evaluating a fair ROE for Kentucky Power. With this as a background, I conducted well-accepted quantitative analyses to estimate the current cost of equity for a reference group of comparable-risk electric utilities. These included the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on allowed ROEs for electric utilities. Based on the cost of equity estimates indicated by my analyses, a fair ROE for Kentucky Power's electric utility operations was evaluated taking into account the specific risks for its jurisdictional utility operations in Kentucky, Kentucky Power's requirements for financial strength that provides benefits to customers, as well as flotation costs, which are properly considered in setting a fair rate of return on equity.

Finally, I tested my recommended ROE for Kentucky Power's electric utility operations based on the results of alternative ROE benchmarks for my proxy group, including applications of the traditional Capital Asset Pricing Model ("CAPM") and reference to expected rates of return. Further, I corroborate my utility quantitative analyses by applying the DCF model to a group of extremely low risk non-utility firms.

II. RETURN ON EQUITY FOR KENTUCKY POWER

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents my conclusions regarding the fair ROEs applicable to Kentucky Power's electric utility operations. This section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Importance of Financial Strength

Q. WHAT ROLE DOES COMMISSION REGULATION PLAY IN SAVING KENTUCKY POWER'S CUSTOMERS MONEY THROUGH SUPPORTING INVESTOR CONFIDENCE?

A. Regulatory signals are a major driver of investors' risk assessment for utilities. Security analysts study commission orders and regulatory policy statements to advise investors where to put their money. If the Commission's actions instill confidence that the regulatory environment is supportive, investors make capital available to Kentucky's utilities on more reasonable terms. When investors are confident that a utility has reasonable and balanced regulation, they will make funds available even in times of turmoil in the financial markets. When Kentucky Powercan negotiate from a position of financial strength it will get a better deal for its customers.

B. Recommended ROE

Q. WHAT IS YOUR RECOMMENDATION AS TO A FAIR ROE FOR KENTUCKY POWER?

A. Based on the adjusted cost of equity ranges estimates presented on page 1 of Exhibit WEA-2, I recommend an ROE of 10.65% for Kentucky Power's electric utility operations.

Q. PLEASE SUMMARIZE THE RESULTS OF THE QUANTITATIVE ANALYSES ON WHICH YOUR RECOMMENDED ROES WERE BASED.

A. The cost of common equity estimates produced by the DCF, ECAPM, and risk premium analyses described subsequently are presented on page 1 of Exhibit WEA-2. Based on these results I recommend an ROE of 10.65% for Kentucky Power's electric utility operations. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with Kentucky Power's jurisdictional utility operations, my analyses focused on a proxy group of twenty-three other utilities with comparable investment risks;
- Based on my evaluation of the strengths and weaknesses of the DCF, ECAPM, and risk premium methods, I concluded that the cost of equity for the proxy group of utilities is in the 9.5% to 11.0% range:
    - In evaluating the results of the DCF model, I considered the relative merits of the alternative growth rates, giving little weight to the internal, "br+sv" growth measures;
    - The forward-looking ECAPM estimates suggested an ROE in the range of 10.6% to 11.6%;
    - The utility risk premium approach implies an ROE estimate on the order of 10.4% to 11.2%.
- I recommend a "bare bones cost of equity, ", that is, the cost of equity before floatation costs, for Kentucky Power of 10.53%, which falls within the upper zone of my recommended 9.5% to 11.0% range:

  - An ROE from above the midpoint of the range is supported by the fact that current bond yields are anomalous, and result in DCF values that are understated;
  - Widespread expectations for higher interest rates emphasize the implication of considering the impact of projected bond yields in evaluating the results of the ECAPM and risk premium methods;
  - Apart from the expected upward trend in capital costs, a cost of equity of 10.53% is consistent with the need to support financial integrity and fund capital investment even under adverse circumstances.
- Adding a flotation cost adjustment of 12 basis points to my 10.53% cost of equity resulted in my recommended ROE of 10.65%.

Q. DOES YOUR ROE RECOMMENDATION REPRESENT A REASONABLE COST FOR KENTUCKY POWER'S CUSTOMERS TO PAY?

A. Yes. Investors have many options vying for their money. They make investment capital available to Kentucky Power only if the expected returns justify the risk. Customers will enjoy reliable and efficient electric service so long as investors are willing to make the capital investments necessary to maintain and improve Kentucky Power's utility system. Providing an adequate return to investors is a necessary cost to ensure that capital is available to Kentucky Power now and in the future. If regulatory decisions increase risk or limit returns to levels that are insufficient to justify the risk, investors will look elsewhere to invest capital.

Apart from the results of the quantitative methods described above, it is crucial to recognize the importance of maintaining a strong financial position so that Kentucky Power remains prepared to respond to unforeseen events that may materialize in the future. While this imperative is reinforced by current capital market conditions, it extends well beyond the financial markets and includes the Company's ability to absorb potential shocks associated with natural disasters such as catastrophic storms and unexpected events. Recent challenges in the capital markets and ongoing economic uncertainties highlight the benefits of bolstering Kentucky Power's financial standing to ensure that the Company can attract the capital needed to secure reliable service at a lower cost for customers. Changing course from the path of financial strength would be extremely shortsighted, especially considering that a combination of events could adversely impact Kentucky Power's ability to serve customers if its current financial strength were not maintained.

Q. WHAT DID THE RESULTS OF ALTERNATIVE ROE BENCHMARKS INDICATE WITH RESPECT TO YOUR RECOMMENDED ROE?

A. The results of alternative ROE benchmarks, which are presented on page 2 of Exhibit WEA-2, support the reasonableness of a "bare bones" ROE of 10.53% for Kentucky Power:

- Applying the traditional CAPM approach suggest a current cost of equity on the order of 10.0% to 11.0%;
- Expected returns for electric utilities suggested an ROE range of 9.7% to 10.7%, excluding any adjustment for flotation costs;
- DCF estimates for an extremely low-risk group of non-utility firms suggest an ROE range of 11.3% to 11.8%.

These tests of reasonableness confirm that my cost of equity recommendations fall in the reasonable range to maintain Kentucky Power's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital.

III. OUTOOK FOR CAPITAL COSTS

Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?

A. Since the onset of recession in 2007, investors have faced a myriad of challenges and uncertainties. More recently, these have included persistent speculation that the economy remains exposed to a potential "double-dip" recession, entrenched unemployment, and exposure to global economic and financial shocks. Partisan political wrangling in Washington has also plagued investors, leading to fears over the "fiscal cliff," the federal debt ceiling, and across-the-board spending cuts mandated by sequestration.

Nevertheless, the U.S. economy appears to be regaining some traction after an anemic close to 2012. The formerly troubled housing market is now experiencing gains and continued increases are expected. Industrial production has strengthened modestly, and apart from the more volatile aircraft and defense components, durable goods orders have increased. On the other hand, automatic cuts in Federal government spending that began March 1, 2013, combined with tax increases enacted earlier this year, are widely expected to depress U.S. economic growth.

While stock prices have reached new highs, market sentiment remains highly sensitive to disappointment, and the Value Line Investment Survey ("Value Line") recently noted, "valuations are rather frothy; there continues to be uncertainty in Washington on the fiscal front … and there are risks on the global front – most notably in the eurozone."[3] The dramatic rise in the price of gold since the beginning of the 2008 recession also attests to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil.

Q. HOW DO CURRENT YIELDS ON PUBLIC UTILITY BONDS COMPARE WITH WHAT INVESTORS HAVE EXPERIENCED IN THE PAST?

A. The yields on utility bonds are at their lowest levels in modern history. Figure WEA-1, below, compares the current yield on long-term, triple-B rated utility bonds with those prevailing since 1968:

FIGURE WEA-1
BBB UTILITY BOND YIELDS – CURRENT VS. HISTORICAL

As illustrated above, prevailing capital market conditions, as reflected in the yields on triple-B utility bonds, are an anomaly when compared with historical experience.

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[3] The Value Line Investment Survey, *Selection & Opinion* at 1073 (Mar. 8, 2013).

Q. DO CURRENT CAPITAL MARKET CONDITIONS PROVIDE A REPRESENTATIVE BASIS ON WHICH TO EVALUATE A FAIR ROE?

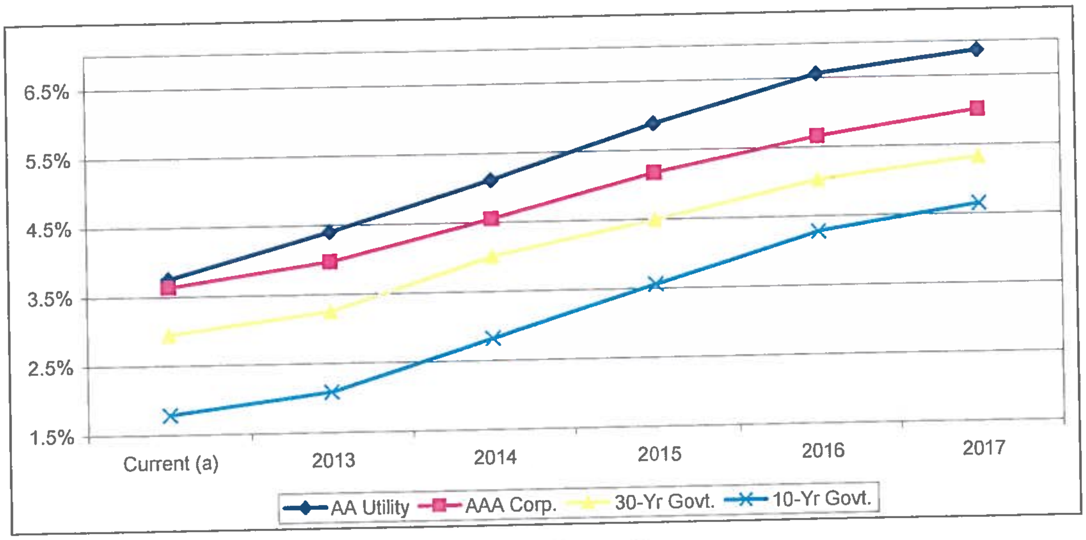
A. No. Current capital market conditions reflect the legacy of the Great Recession, but they are not representative of what investors expect in the future. As discussed above, investors have had to contend with a level of economic uncertainty and capital market volatility that has been unprecedented in recent history. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds. As a result of this "flight to safety," Treasury bond yields have been pushed significantly lower in the face of political, economic, and capital market risks. In addition, the Federal Reserve has implemented measures designed to push interest rates to historically low levels in an effort to stimulate the economy and bolster employment.

Q. ARE THESE VERY LOW INTEREST RATES EXPECTED TO CONTINUE?

A. No. Investors do not anticipate that these low interest rates will continue into the future. It is widely anticipated that as the economy stabilizes and resumes a more robust pattern of growth, long-term capital costs will increase significantly from present levels. Figure WEA-2 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value

Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE WEA-2
INTEREST RATE TRENDS



(a) Based on monthly average bond yields for the six-month period Sep. 2012 - Feb. 2013 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm.

<u>Sources</u>:

Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013)
IHS Global Insight, U.S. Economic Outlook at 25 (Oct. 2012)
Blue Chip Financial Forecasts, Vol. 31, No. 12 (Dec. 1, 2012)
Standard & Poor's Corporation, "U.S. Economic Forecast: Like A Box Of Chocolates," RatingsDirect (Feb. 19, 2013)
Energy Information Administration, Annual Energy Outlook 2013 Early Release (Dec. 5, 2012)

These forecasting services are highly regarded and widely referenced, with FERC incorporating forecasts from IHS Global Insight and the EIA in its preferred DCF model for natural gas pipelines. As evidenced above, there is a clear consensus in the investment community that the cost of long-term capital will be significantly higher over the 2013-2017 period than it is currently.

Q. DO RECENT STATEMENTS OF THE FEDERAL RESERVE SUPPORT THE CONTENTION THAT CURRENT LOW INTEREST RATES WILL CONTINUE INDEFINITELY?

A. No. While the Federal Reserve continues to express support for maintaining current stimulus policies, it has also has begun to map out a strategy for reducing its bond-buying program based on conditions for employment and inflation. The Wall Street Journal noted the close link between investors' required returns in the capital markets and the Federal Reserve's policy pronouncements:

> Stock prices fell after the minutes were released, with many investors surprised to learn the programs could end sooner than they thought. ... The reaction was a potential warning from investors, who have grown accustomed to repeated Fed stimulus efforts since the 2008 financial crisis. The market reaction showed that even discussion about ending the programs, also known as quantitative easing, or QE, could jolt stocks and bonds.[4]

Similarly, Value Line also highlighted the impact on investors of ongoing uncertainties over a potential revision of Federal Reserve's stimulus policies:

> Volatility returned to the markets with gusto in February. ... One contributor to the broader market's roller coaster ride last month was conflicting remarks from the Federal Reserve regarding its easy-money policies.[5]

More recently, the Wall Street Journal observed that the plan to reduce bond purchases "is of intense interest in the financial markets."[6] While noting the goal of managing "highly unpredictable market expectations," the article warned that the Federal Reserve's actions "might not be the clear and steady path markets

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[4] *Id.*

[5] The Value Line Investment Survey, *Selection and Opinion* at 1074 (Mar. 8, 2013).

[6] Hilsenrath, Jon, "Fed Maps Exit from Stimulus, *Wall Street Journal* at A1 (May 11, 2013).

expect."[7] These discussions highlight concerns for investors and supports expectations for higher interest rates as the economy and labor markets continue to recover.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR KENTUCKY POWER MORE GENERALLY?

A. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets. As a result, current capital costs are not representative of what is likely to prevail over the near-term future, with this conclusion being demonstrated by comparisons to the historical record and independent forecasts. Recognized economic forecasting services project that long-term capital costs will increase from present levels. To address the reality of current capital markets, the Commission should consider near-term forecasts for public utility bond yields in evaluating the reasonableness of individual cost of equity estimates and in selecting a fair ROE for Kentucky Power from within the range of reasonableness. As I will discuss below, this result is supported by economic studies that show that risk premiums are higher when interest rates are at very low levels.

[7] *Id.*

IV. COMPARABLE RISK PROXY GROUPS

Q. HOW DID YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR KENTUCKY POWER?

A. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply quantitative methods such as the DCF and ECAPM to a proxy group of publicly traded companies that investors regard as risk-comparable.

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

A. In order to reflect the risks and prospects associated with Kentucky Powerjurisdictional electric operations, my analyses focused on a reference group of other utilities composed of those companies included in Value Line's electric utility industry groups with a:

1. Corporate credit rating from Standard & Poor's ("S&P") of "BBB+", "BBB", or "BBB-",
2. Value Line Safety Rank of "2" or "3",
3. Value Line Financial Strength Rating of "B+" or higher, and
4. Market capitalization of $1.6 billion or greater.

In addition, I excluded two utilities (Entergy Corporation and ITC Holdings Corp.) that otherwise would have been in the proxy group, but are not appropriate for inclusion because of current involvement in a major acquisition. These criteria resulted in a proxy group composed of twenty-three companies, which I will refer to as the "Electric Group."

Q. DO THE SCREENING CRITERIA USED TO ESTABLISH THE ELECTRIC GROUP PROVIDE OBJECTIVE EVIDENCE TO EVALUATE INVESTORS' RISK PERCEPTIONS?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole, and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in my experience Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. ... Value Line betas are computed on a theoretically sound basis using a

broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[8]

Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUP COMPARE TO KENTUCKY POWER?

A. Table WEA-1 compares the Electric Group with Kentucky Power across the four key indicia of investment risk discussed above. Because Kentucky Power has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, AEP:

TABLE WEA-1
COMPARISON OF RISK INDICATORS

	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Electric Group	BBB	2	B++	0.72
Kentucky Power	BBB	3	B++	0.65

Q. WHAT DOES THIS COMPARISON INDICATE REGARDING INVESTORS' ASSESSMENT OF THE RELATIVE RISKS ASSOCIATED WITH YOUR ELECTRIC GROUP?

A. As shown above, the Company's corporate rating and Value Line Financial Strength Rating are identical to the averages for the Electric Group. Meanwhile, the average Value Line Safety Rank for Kentucky Power suggests more risk than for the Electric Group, while the beta value attributable to the Company suggests somewhat less risk. Considered together, a comparison of these objective measures, which incorporate a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors,

[8] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

indicates that investors would likely conclude that the overall investment risks for Kentucky Power are comparable to those of the firms in the Electric Group.

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN KENTUCKY POWER'S CAPITAL STRUCTURE?

A. The test year capital structure used to compute the overall rate of return for Kentucky Power includes approximately 45.80% common equity.

Q. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE ELECTRIC GROUP?

A. As shown on page 1 of Exhibit WEA-3, for the firms in the Electric Group, common equity ratios at December 31, 2012 averaged 47.9% of total long-term debt and equity , with Value Line expecting an average common equity ratio of 49.7% for its three-to-five year forecast horizon. Thus, Kentucky Power's common equity ratio indicates somewhat greater financial risk than investors would associate with the Electric Group.

V. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF, ECAPM, and risk premium analyses conducted to estimate the cost of common equity for the proxy group of comparable risk firms and evaluate expected earned rates of return for utilities. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

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

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

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

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

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

$$k_i = R_f + RP_i$$

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

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

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

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

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

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

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

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. DOES THE FACT THAT KENTUCKY POWER IS A SUBSIDIARY OF AEP IN ANY WAY ALTER THESE FUNDAMENTAL STANDARDS UNDERLYING A FAIR ROE?

A. No. While Kentucky Power has no publicly traded common stock and AEP is its only shareholder, this does not change the standards governing the determination of a fair ROE for the Company. Ultimately, the common equity that is required to support Kentucky Power's utility operations must be raised in the capital markets, where investors consider the Company's ability to offer a rate of return that is competitive with other risk-comparable alternatives. As noted above, Kentucky Power must compete with other investment opportunities and unless there is a reasonable expectation that the Company can earn a return that is commensurate with its underlying risks, capital will be allocated elsewhere, Kentucky Power's financial integrity will be weakened, and investors will demand an even higher rate of return. The Company's ability to offer a reasonable return on investment is a necessary ingredient in ensuring that customers continue to enjoy economical rates and reliable service.

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

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

B. Discounted Cash Flow Analyses

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

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

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

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

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

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

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[9]

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

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

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

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

[9] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

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

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

A. I applied the constant growth DCF model to estimate the cost of common equity for Kentucky Power, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

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

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

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

A. For D_1, I used estimates of dividends to be paid by each of these utilities over the next 12 months, obtained from Value Line. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Electric Group are presented on Exhibit WEA-4. As shown on page 1, dividend yields for the firms in the Electric Group ranged from 2.7% to 4.9%.

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

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

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

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to distort historical growth measures, they are neither representative of long-term growth for the utility industry nor the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

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

A. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratio for electric utilities falling significantly. As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS"). Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that dividend growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. DID PROFESSOR MYRON J. GORDON, WHO ORIGINATED THE DCF APPROACH, RECOGNIZE THE PIVOTAL ROLE THAT EARNINGS PLAY IN FORMING INVESTORS' EXPECTATIONS?

A. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[10]

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[10] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE ELECTRIC GROUP?

A. The earnings growth projections for each of the firms in the Electric Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on page 2 of Exhibit WEA-4.[11]

Q. SOME ARGUE THAT ANALYSTS' ASSESSMENTS OF GROWTH RATES ARE BIASED. DO YOU BELIEVE THESE PROJECTIONS ARE APPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A. Yes, I do. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The

[11] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (*e.g.*, Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. <u>The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.</u>[12]

Similarly, the Commission has also indicated its preference for relying on analysts' projections in establishing investors' expectations:

> KU's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more

[12] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).

> persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance, especially given the current state of the economy.[13]

Q. HAVE OTHER REGULATORS ALSO RECOGNIZED THAT ANALYSTS' GROWTH RATE ESTIMATES ARE AN IMPORTANT AND MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A. Yes. FERC has expressed a clear preference for projected EPS growth rates from IBES in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities, and has expressly rejected reliance on other sources.[14] As FERC concluded:

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[15]

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[13] *Order*, Case No. 2009-00548 at 30-31 (Jul. 30, 2010).
[14] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 99 FERC ¶ 63,011 at P 53 (2002); *Golden Spread Elec. Coop. Inc.*, 123 FERC ¶ 61,047 (2008).
[15] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) ((footnote omitted).

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. WHAT IS THE PURPOSE OF THE "SV" TERM?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. **WHAT GROWTH RATE DOES THE EARNINGS RETENTION METHOD SUGGEST FOR THE ELECTRIC GROUP?**

A. The sustainable, "br+sv" growth rates for each firm in the Electric Group are summarized on page 2 of Exhibit WEA-4, with the underlying details being presented on Exhibit WEA-5. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. **ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE "BR+SV" GROWTH RATE?**

A. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[16]

I have included the "sustainable growth" approach for completeness, but I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

Q. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE ELECTRIC GROUP USING THE DCF MODEL?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit WEA-4.

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with

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[16] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006).

an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[17] and in its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[18]

Q. WHAT INTEREST RATE BENCHMARK DID YOU CONSIDER IN EVALUATING THE DCF RESULTS FOR KENTUCKY POWER?

A. As noted earlier, S&P has assigned a corporate credit rating of "BBB" to Kentucky Power. Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 4.5% in April 2013.[19] It is inconceivable

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[17] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[18] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").
[19] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

that investors are not requiring a substantially higher rate of return for holding common stock.

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth. As shown in Table WEA-2 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of approximately 6.6% over the period 2013-2017:

TABLE WEA-2
IMPLIED BBB BOND YIELD

	2013-17
Projected AA Utility Yield	
IHS Global Insight (a)	5.65%
EIA (b)	5.90%
Average	5.77%
Current BBB - AA Yield Spread (c)	0.78%
Implied Triple-B Utility Yield	**6.55%**

(a) IHS Global Insight, U.S. Economic Outlook at 25 (Oct. 2012)
(b) Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Nov. 2012 - Apr. 2013

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb 250 basis points through 2018.[20]

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE ELECTRIC GROUP?

A. As highlighted on page 3 of Exhibit WEA-4, low-end DCF estimates ranged from –3.0% to 6.9%. Based on my professional experience, the risk-return principle that is fundamental to finance, and the review of utility allowed ROEs presented on Exhibit WEA-7, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock.. As a result, consistent with the upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. IS THERE A BASIS TO EXCLUDE DCF ESTIMATES AT THE HIGH END OF THE RANGE?

A. No. The upper end of the DCF range for the Electric Group was set by a cost of equity estimate of 14.9%. While this cost of equity estimate may exceed the majority of the remaining values, remaining low-end estimates in the 7% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return.

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[20] *Blue Chip Financial Forecasts*, Vol. 31, No. 12 (Dec. 1, 2012).

Q. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE ELECTRIC GROUP?

A. As shown on page 3 of Exhibit WEA-4 and summarized in Table WEA-3, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE WEA-3
DCF RESULTS – ELECTRIC GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	9.2%	10.9%
IBES	8.8%	9.7%
Zacks	8.5%	8.7%
br + sv	8.0%	8.3%

C. Empirical Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN EVALUATING A FAIR ROE USING THE CAPM?

A. A myriad of empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[21]

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[21] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).

As discussed in *New Regulatory Finance*, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

This equation, and the associated weighting factors, recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q. HOW DID YOU APPLY THE ECAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A. Application of the ECAPM to the Electric Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit WEA-6. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the 390 dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the average of the EPS growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 390 individual firms, current estimates imply an average growth rate over the next five years of 10.1%. Combining this average growth rate with a year-ahead dividend yield of 2.4% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.5%.

Subtracting a 3.3% risk-free rate based on the average yield on 30-year Treasury bonds for 2013 produced a market equity risk premium of 9.2%.

Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE ECAPM?

A. As indicated earlier, I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE ECAPM?

A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[22]

Because financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of

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[22] *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at p. 85.

equity.[23] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of 6.0% for a company in the first decile (market capitalization less than $254.6 million), to a reduction of 37 basis points for firms in the tenth decile (market capitalization between $17.6 billion and $626.6 billion). Accordingly, my ECAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Electric Group.

Q. WHAT IS THE IMPLIED ROE FOR THE ELECTRIC GROUP USING THE ECAPM APPROACH?

A. As shown on page 1 of Exhibit WEA-6, a forward-looking application of the ECAPM approach resulted in an average unadjusted ROE estimate of 10.6%.[24] After adjusting for the impact of firm size, the ECAPM approach implied an average cost of equity of 11.4% for the Electric Group, with a midpoint cost of equity estimate of 10.8%.

Q. DID YOU ALSO APPLY THE ECAPM USING FORECASTED BOND YIELDS?

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. Accordingly, in addition to the use of current bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip. As shown on page 2 of Exhibit WEA-6, incorporating a forecasted Treasury bond yield for 2013-2017

[23] *Id.* at Table C-1.
[24] The midpoint of the unadjusted ECAPM range was 10.3%.

implied a cost of equity of approximately 10.8% for the Electric Group, or 11.6% after adjusting for the impact of relative size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 10.5% and 11.1%, respectively.

D. Utility Risk Premium

Q. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A. I based my estimates of equity risk premiums for utilities on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR KENTUCKY POWER?

A. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (*e.g.*, stock prices dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED ROES?

A. Surveys of previously authorized ROEs are frequently referenced as the basis for estimating equity risk premiums. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit WEA-7, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2012.[25] As shown on page 3 of Exhibit WEA-7, over this period, these equity risk premiums for electric utilities averaged 3.47%, and the yield on public utility bonds averaged 8.79%.

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[25] My analysis encompasses the entire period for which published data is available.

Q. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates.[26] In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Finally, it is important to recognize that the historical focus of risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing utility service. As a result, they are likely to understate the cost of equity for a firm operating in today's utility industry.

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[26] *See, e.g.*, Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

Q. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED ROES?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit WEA-7, the equity risk premium for electric utilities increased approximately 42 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit WEA-7, with an average yield on public utility bonds for 2013 of 4.75%, this implied a current equity risk premium of 5.17% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds for 2013 of 5.21% implies a current cost of equity of approximately 10.4%.

Q. WHAT RISK PREMIUM COST OF EQUITY ESTIMATES WERE PRODUCED FOR KENTUCKY POWER'S UTILITY OPERATIONS AFTER INCORPORATING FORECASTED BOND YIELDS?

A. As shown on page 2 of Exhibit WEA-7, incorporating a forecasted yield for 2013-2017 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.60% for electric utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2013-2017 of 6.55% resulted in an implied cost of equity of approximately 11.2%.

E. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q. IS THERE A THEORETICAL AND PRACTICAL BASIS TO INCLUDE A FLOTATION COST ADJUSTMENT IN THIS CASE?

A. Yes. First, an adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[27] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[28]

[27] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985.
[28] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. There are a number of ways in which a flotation cost adjustment can be calculated, but the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[29]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%,[30] with AEP incurring issuance costs equal to approximately 3.02% of the gross proceeds from its 2009 public offering of common stock.[31] Multiplying this 3.02% expense percentage for AEP by a representative dividend yield of 4.0% produces a flotation cost adjustment on the order of 12 basis points.

VI. OTHER ROE BENCHMARKS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section presents alternative tests to demonstrate that the end-results of the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE given the facts and circumstances of Kentucky Power. The first test is based on

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[29] Roger A. Morin, "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc. at 166* (1994).

[30] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[31] American Electric Power Company, Inc., *Prospectus Supplement (To Prospectus dated December 22, 2008)* (Apr. 1, 2009). Net proceeds from AEP's sale of 69 million shares of common stock raised approximately $1.64 billion of additional equity capital.

applications of the traditional CAPM analysis using current and projected interest rates. The second test is based on expected earned returns for electric utilities. Finally, I present a DCF analysis for an extremely low risk group of non-utility firms, with which Kentucky Power must compete for investors' money.

A. Capital Asset Pricing Model

Q. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY THE TRADITIONAL CAPM?

A. My applications of the traditional CAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the ECAPM. As shown on page 1 of Exhibit WEA-8, applying the forward-looking CAPM approach to the firms in the Electric Group results in an average theoretical cost of equity estimate of 10.0%, or 10.7% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.

As shown on page 2 of Exhibit WEA-8, incorporating a forecasted Treasury bond yield for 2013-2017 implied a cost of equity of approximately 10.3% for the Electric Group, or 11.0% after adjusting for the impact of relative size.

B. Expected Earnings Approach

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF COMMON EQUITY?

A. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation. The expected earnings approach is consistent with the economic rationale underpinning established regulatory standards, which specifies a methodology to determine an ROE benchmark based on earned rates of return for a peer group of other regional utilities.

Q. HOW IS THE EXPECTED EARINGS APPROACH TYPICALLY IMPLEMENTED?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices- both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is directly analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. **WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?**

A. Value Line's projections imply an average rate of return on common equity for the electric utility industry of 10.1% over its 2015-2017 forecast horizon.[32] Meanwhile, for the firms in the Electric Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit WEA-9. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit WEA-5. As shown on Exhibit WEA-9, Value Line's projections for the Electric Group suggest an average ROE of approximately 9.6%, with a midpoint value of 10.8%.

C. Extremely Low Risk Non-Utility DCF

Q. **WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR KENTUCKY POWER?**

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. With

[32] The Value Line Investment Survey (Feb. 22, Mar. 22, & May 24, 2013). Recall that Value Line reports return on year-end equity so the equivalent return on average equity would be higher.

regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of low-risk risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Group".

Q. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. As the Commission has previously acknowledged:

> Concerning the issue of using a non-utility proxy group in analyzing the required ROE for a utility, the Commission agrees with KU that investors are always looking for the best investment opportunity and that a utility is in competition with unregulated firms...[33]

Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

[33] *Order*, Case No. 2009-00548 at 31 (Jul. 30, 2010).

Q. IS IT CONSISTENT WITH THE BLUEFIELD AND HOPE CASES TO CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?

A. Yes. The cost of equity capital in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[34]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies.

[34] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

Q. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A. My comparable risk proxy group was composed of those United States companies followed by Value Line that:

1) pay common dividends;
2) have a Safety Rank of "1";
3) have a Financial Strength Rating of "B++" or greater;
4) have a beta of 0.60 or less; and
5) have investment grade credit ratings from S&P[35].

[35] Credit rating firms, such as S&P, use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'AAA', 'AA', 'A', and 'BBB' ratings are considered investment grade. Credit ratings for bonds below these designations ('BB', 'B', 'CCC', etc.) are considered speculative grade, and are commonly referred to as "junk bonds". The term "investment grade" refers to bonds with ratings in the 'BBB' category and above.

Q. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE ELECTRIC GROUP?

A. Table WEA-4 compares the Non-Utility Group with the Electric Group and Kentucky Power across the four key risk measures discussed earlier:

TABLE WEA-4
COMPARISON OF RISK INDICATORS

	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Non-Utility Group	A	1	A+	0.58
Electric Group	BBB	2	B++	0.72
Kentucky Power	BBB	3	B++	0.65

As shown above, the average credit rating, Safety Rank, Financial Strength Rating, and beta for the Non-Utility Group suggest less risk than for Kentucky Power and the proxy group of electric utilities. When considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the Electric Group and Kentucky Power are greater than those of the firms in the Non-Utility Group.

Q. HAS THE COMMISSION PREVIOUSLY EXPRESSED CONCERNS WITH THE USE OF A NON-UTILITY PROXY GROUP?

A. Yes. The Commission has previously declined to rely on a non-utility proxy group, finding that non-utility companies are riskier than Kentucky Power or other electric utilities.[36] Specifically, the Commission previously determined that "the relative risk of electric utilities as reflected in their Value Line Betas supports the attractiveness of utility investments in comparison to riskier alternatives."[37]

Q. **HAVE YOU ALTERED YOUR ANALYSIS TO ADDRESS THE COMMISSIONS CONCERN?**

A. Yes. First, my recommended ROEs for Kentucky Power's utility operations were not based on the DCF results for the Non-Utility Group. Rather, I considered the indicated cost of equity for the Non-Utility Group solely as an alternative benchmark to confirm the reasonableness of my recommendations.

Second, the proxy group of non-utility firms that I referenced in connection with Case No. 2009-00548 was a broad group made up of almost 70 companies with much greater diversity in their overall risk profiles. In contrast, the group of eleven non-utility firms that I relied on in this case was specifically tailored to address the Commission's concerns by using criteria that reflect an extremely low risk profile. Accordingly, I restricted the non-utility firms to those with beta values of 0.60 or less. As illustrated above in Table WEA-4, the average beta for the Non-Utility Group is significantly less that those corresponding to the Electric Group and Kentucky Power.

The eleven companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Colgate-Palmolive, McDonalds, and Wal-Mart, have long corporate histories, well-established track records, and

[36] *Order, Case No. 2009-00548 at 31 (Jul 30, 2010)*
[37] *Order, Case No. 2009-00548 at 31 (Jul 30, 2010)*

exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group approaching 3%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A. I applied the DCF model to the Non-Utility Group using the same analysts EPS growth projections described earlier for the Electric Group, with the results being presented in Exhibit WEA-10. As summarized in Table WEA-5, below, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE WEA-5
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	11.4%	11.3%
IBES	11.4%	11.8%
Zacks	11.4%	11.8%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. HOW CAN YOU RECONCILE THESE DCF RESULTS FOR THE NON-UTILITY GROUP AGAINST THE SIGNIFICANTLY LOWER ESTIMATES PRODUCED FOR YOUR GROUP OF UTILITIES?

A. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As I documented earlier, the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings, Value Line's Safety Rank, Financial Strength, and beta – are lower than the risks investors associate with the Electric Group. The objective evidence provided by these observable risk measures rules out a conclusion that the higher non-utility DCF estimates are associated with higher investment risk.

Rather, the divergence between the DCF results for these groups of utility and non-utility firms can be attributed to the fact that DCF estimates invariably depart from the returns that investors actually require because their expectations may not be captured by the inputs to the model, particularly the assumed growth rate. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for Kentucky Power. There is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector, and the divergence between the DCF estimates for the group of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result. The results of the Non-Utility Group DCF suggests that the 10.65% recommended ROE for Kentucky Power's electric operations is a conservative estimate of a fair return, particularly since this recommended ROE includes a flotation cost adjustment in addition to the bare bones cost of equity.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ALTERNATIVE ROE BENCHMARKS.

A. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 2 of Exhibit WEA-2, and summarized in Table WEA-6, below:

TABLE WEA-6
SUMMARY OF ALTERNATIVE ROE BENCHMARKS

	Electric Group	
	Average	**Midpoint**
CAPM - 2013 Bond Yield		
Unadjusted	10.0%	9.5%
Size Adjusted	10.7%	10.0%
CAPM - Projected Bond Yield		
Unadjusted	10.3%	9.9%
Size Adjusted	11.0%	10.4%
Expected Earnings		
Industry	10.2%	
Proxy Group	9.7%	10.7%
Non-Utility DCF		
Value Line	11.4%	11.3%
IBES	11.4%	11.8%
Zacks	11.4%	11.8%

The results of these alternative benchmarks confirm my conclusion that a "bare bones" ROE of 10.53% for Kentucky Power's electric utility operations is reasonable.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

Director, Economic Research Division,
Public Utility Commission of Texas
(Dec. 1977 to Aug. 1979)

Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.

Manager, Financial Education,
International Paper Company
New York City
(Feb. 1977 to Nov. 1977)

Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance, The University of Texas at Austin (Sep. 1979 to May 1981) Assistant Professor of Finance, (Sep. 1975 to May 1977)	Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.
Assistant Professor of Business, University of North Carolina at Chapel Hill (Sep. 1972 to Jul. 1975)	Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance, University of North Carolina at Chapel Hill (Jan. 1969 to Aug. 1972)	Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics. Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*
B.A., Economics, Emory University, Atlanta, Georgia (Sep. 1961 to Jun. 1965)	Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in almost 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Co-chair, Synchronous Interconnection Committee established by Texas Legislature to study interconnection of Texas with national grid; Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock

Advisory Committee by Texas Agricultural Commissioner; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Treasurer, Dripping Springs Presbyterian Church; Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

"Economic Perspectives on Texas Water Resources," with Robert M. Avera and Felipe Chacon in *Essentials of Texas Water Resources,* Mary K. Sahs, ed. State Bar of Texas (2012).

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

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"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

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"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

ROE ANALYSES

SUMMARY OF RESULTS

	Average	Midpoint
DCF		
Value Line	9.2%	10.9%
IBES	8.8%	9.7%
Zacks	8.5%	8.7%
Internal br + sv	8.0%	8.3%
Empirical CAPM - 2013 Yield		
Unadjusted	10.6%	10.3%
Size Adjusted	11.4%	10.8%
Empirical CAPM - Projected Yield		
Unadjusted	10.8%	10.5%
Size Adjusted	11.6%	11.1%
Utility Risk Premium		
Current Bond Yields	10.4%	
Projected Bond Yields	11.2%	
Cost of Equity Recommendation		
Cost of Equity Range	9.5% --	11.0%
Recommended Point Estimate	10.53%	
Flotation Cost Adjustment		
Dividend Yield	4.00%	
Flotation Cost Percentage	3.02%	
Adjustment	0.12%	
ROE Recommendation	**10.65%**	

CHECKS OF REASONABLENESS

	Average	Midpoint
CAPM - 2013 Bond Yield		
Unadjusted	10.0%	9.5%
Size Adjusted	10.7%	10.0%
CAPM - Projected Bond Yield		
Unadjusted	10.3%	9.9%
Size Adjusted	11.0%	10.4%
Expected Earnings		
Industry	10.2%	
Proxy Group	9.7%	10.7%
Non-Utility DCF		
Value Line	11.4%	11.3%
IBES	11.4%	11.8%
Zacks	11.4%	11.8%

CAPITAL STRUCTURE

UTILITY GROUP

	Company	At Fiscal Year-End 2012 (a)			Value Line Projected (b)		
		Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	ALLETE	45.9%	0.0%	54.1%	42.5%	0.0%	57.5%
2	Ameren Corp.	50.8%	0.0%	49.2%	50.0%	1.0%	49.0%
3	American Elec Pwr	49.9%	0.0%	50.1%	45.5%	0.0%	54.5%
4	Avista Corp.	50.1%	0.0%	49.9%	48.5%	0.0%	51.5%
5	Black Hills Corp.	45.8%	0.0%	54.2%	51.5%	0.0%	48.5%
6	CMS Energy Corp.	69.1%	0.0%	30.9%	60.0%	0.5%	39.5%
7	DTE Energy Co.	50.4%	0.0%	49.6%	50.0%	0.0%	50.0%
8	Duke Energy Corp.	48.5%	0.1%	51.4%	52.0%	0.0%	48.0%
9	Edison International	45.2%	8.6%	46.2%	46.0%	7.5%	46.5%
10	Exelon Corp.	46.2%	0.7%	53.1%	44.0%	0.5%	55.5%
11	FirstEnergy Corp.	56.7%	0.0%	43.3%	55.5%	0.0%	44.5%
12	Great Plains Energy	47.2%	0.6%	52.2%	44.5%	0.5%	55.0%
13	Hawaiian Elec.	47.2%	0.0%	52.8%	47.5%	1.0%	51.5%
14	IDACORP, Inc.	46.6%	0.0%	53.4%	46.0%	0.0%	54.0%
15	NV Energy, Inc.	58.6%	0.0%	41.4%	46.5%	0.0%	53.5%
16	PG&E Corp.	44.7%	0.0%	55.3%	50.0%	0.5%	49.5%
17	Portland General Elec.	65.0%	0.0%	35.0%	48.0%	0.0%	52.0%
18	PPL Corp.	42.4%	0.0%	57.6%	54.0%	0.0%	46.0%
19	SCANA Corp.	55.2%	0.0%	44.8%	53.5%	0.0%	46.5%
20	Sempra Energy	53.6%	0.1%	46.3%	53.5%	0.5%	46.0%
21	TECO Energy	56.5%	0.0%	43.5%	55.0%	0.0%	45.0%
22	UIL Holdings	53.1%	10.9%	36.0%	54.5%	0.0%	45.5%
23	Westar Energy	49.4%	0.0%	50.6%	50.0%	0.0%	50.0%
	Average	**51.2%**	**0.9%**	**47.9%**	**49.9%**	**0.5%**	**49.5%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Mar. 22, May 3, & May 24, 2013).

DCF MODEL - UTILITY GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	ALLETE	$ 50.47	$ 1.92	3.8%
2	Ameren Corp.	$ 35.80	$ 1.60	4.5%
3	American Elec Pwr	$ 49.97	$ 1.98	4.0%
4	Avista Corp.	$ 28.14	$ 1.24	4.4%
5	Black Hills Corp.	$ 47.43	$ 1.53	3.2%
6	CMS Energy Corp.	$ 28.96	$ 1.04	3.6%
7	DTE Energy Co.	$ 71.68	$ 2.62	3.7%
8	Duke Energy Corp.	$ 73.22	$ 3.11	4.2%
9	Edison International	$ 51.26	$ 1.38	2.7%
10	Exelon Corp.	$ 36.00	$ 1.24	3.4%
11	FirstEnergy Corp.	$ 44.72	$ 2.20	4.9%
12	Great Plains Energy	$ 23.83	$ 0.90	3.8%
13	Hawaiian Elec.	$ 27.61	$ 1.24	4.5%
14	IDACORP, Inc.	$ 48.31	$ 1.52	3.1%
15	NV Energy, Inc.	$ 20.91	$ 0.78	3.7%
16	PG&E Corp.	$ 47.23	$ 1.82	3.9%
17	Portland General Elec.	$ 31.76	$ 1.12	3.5%
18	PPL Corp.	$ 32.28	$ 1.48	4.6%
19	SCANA Corp.	$ 52.99	$ 2.04	3.8%
20	Sempra Energy	$ 82.42	$ 2.55	3.1%
21	TECO Energy	$ 18.71	$ 0.88	4.7%
22	UIL Holdings	$ 40.88	$ 1.73	4.2%
23	Westar Energy	$ 33.89	$ 1.36	4.0%
	Average			**3.9%**

(a) Average of closing prices for 30 trading days ended May 24, 2013.
(b) The Value Line Investment Survey, Summary & Index (May 3, 2013).

DCF MODEL - UTILITY GROUP

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	ALLETE	7.0%	6.0%	6.5%	5.0%
2	Ameren Corp.	-1.0%	-1.8%	3.0%	2.8%
3	American Elec Pwr	4.5%	3.6%	3.4%	4.1%
4	Avista Corp.	4.0%	4.5%	4.3%	2.9%
5	Black Hills Corp.	11.5%	6.0%	6.0%	4.1%
6	CMS Energy Corp.	7.0%	5.9%	5.8%	5.0%
7	DTE Energy Co.	4.0%	4.6%	4.7%	3.8%
8	Duke Energy Corp.	4.0%	4.2%	4.2%	2.6%
9	Edison International	2.5%	-1.9%	4.8%	6.3%
10	Exelon Corp.	-2.5%	-3.4%	-2.3%	4.5%
11	FirstEnergy Corp.	3.5%	2.7%	0.6%	2.4%
12	Great Plains Energy	6.5%	6.4%	5.6%	3.3%
13	Hawaiian Elec.	5.5%	3.3%	4.2%	4.5%
14	IDACORP, Inc.	2.0%	4.0%	4.0%	4.2%
15	NV Energy, Inc.	8.0%	3.1%	3.1%	3.1%
16	PG&E Corp.	4.0%	3.1%	1.4%	3.9%
17	Portland General Elec.	3.5%	4.8%	5.9%	3.6%
18	PPL Corp.	0.0%	7.0%	-4.0%	5.0%
19	SCANA Corp.	4.5%	4.5%	4.3%	5.3%
20	Sempra Energy	4.5%	5.7%	4.3%	5.1%
21	TECO Energy	3.5%	2.9%	3.7%	4.2%
22	UIL Holdings	4.0%	8.2%	4.0%	3.0%
23	Westar Energy	5.0%	4.8%	5.1%	4.2%

(a) The Value Line Investment Survey (Mar. 22, May 3, & May 24, 2013).
(b) www.finance.yahoo.com (retrieved May 15, 2013).
(c) www.zacks.com (retrieved May 15, 2013).
(d) See Exhibit WEA-5.

DCF MODEL - UTILITY GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	ALLETE	10.8%	9.8%	10.3%	8.8%
2	Ameren Corp.	3.5%	2.7%	7.5%	7.3%
3	American Elec Pwr	8.5%	7.6%	7.4%	8.1%
4	Avista Corp.	8.4%	8.9%	8.7%	7.3%
5	Black Hills Corp.	14.7%	9.2%	9.2%	7.3%
6	CMS Energy Corp.	10.6%	9.5%	9.4%	8.6%
7	DTE Energy Co.	7.7%	8.3%	8.4%	7.4%
8	Duke Energy Corp.	8.2%	8.4%	8.4%	6.8%
9	Edison International	5.2%	0.8%	7.5%	9.0%
10	Exelon Corp.	0.9%	0.0%	1.1%	8.0%
11	FirstEnergy Corp.	8.4%	7.6%	5.5%	7.3%
12	Great Plains Energy	10.3%	10.2%	9.4%	7.1%
13	Hawaiian Elec.	10.0%	7.8%	8.7%	9.0%
14	IDACORP, Inc.	5.1%	7.1%	7.1%	7.3%
15	NV Energy, Inc.	11.7%	6.8%	6.8%	6.8%
16	PG&E Corp.	7.9%	7.0%	5.3%	7.7%
17	Portland General Elec.	7.0%	8.3%	9.4%	7.1%
18	PPL Corp.	4.6%	11.6%	0.6%	9.6%
19	SCANA Corp.	8.3%	8.4%	8.1%	9.2%
20	Sempra Energy	7.6%	8.7%	7.4%	8.2%
21	TECO Energy	8.2%	7.6%	8.4%	8.9%
22	UIL Holdings	8.2%	12.4%	8.2%	7.2%
23	Westar Energy	9.0%	8.8%	9.1%	8.2%
	Average (b)	**9.2%**	**8.8%**	**8.5%**	**8.0%**
	Midpoint (c)	**10.9%**	**9.7%**	**8.7%**	**8.3%**

(a) Sum of dividend yield (Exhibit WEA-4, p. 1) and respective growth rate (Exhibit WEA-4, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - UTILITY GROUP

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2017					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	ALLETE	$3.75	$2.20	$36.25	41.3%	10.3%	1.0274	10.6%	4.4%	0.0262	0.2368	0.62%	5.0%
2	Ameren Corp.	$2.50	$1.70	$29.50	32.0%	8.5%	1.0124	8.6%	2.7%	0.0110	0.0923	0.10%	2.8%
3	American Elec Pwr	$3.75	$2.30	$38.25	38.7%	9.8%	1.0237	10.0%	3.9%	0.0102	0.2350	0.24%	4.1%
4	Avista Corp.	$2.00	$1.40	$24.00	30.0%	8.3%	1.0204	8.5%	2.6%	0.0170	0.2000	0.34%	2.9%
5	Black Hills Corp.	$3.00	$1.70	$33.00	43.3%	9.1%	1.0198	9.3%	4.0%	0.0050	0.1200	0.06%	4.1%
6	CMS Energy Corp.	$2.00	$1.30	$16.00	35.0%	12.5%	1.0307	12.9%	4.5%	0.0127	0.4182	0.53%	5.0%
7	DTE Energy Co.	$4.75	$3.05	$52.50	35.8%	9.0%	1.0301	9.3%	3.3%	0.0230	0.1923	0.44%	3.8%
8	Duke Energy Corp.	$5.00	$3.35	$64.25	33.0%	7.8%	1.0106	7.9%	2.6%	0.0017	0.0115	0.00%	2.6%
9	Edison International	$4.25	$1.80	$40.00	57.6%	10.6%	1.0329	11.0%	6.3%	-	0.2381	0.00%	6.3%
10	Exelon Corp.	$2.75	$1.40	$30.50	49.1%	9.0%	1.0199	9.2%	4.5%	0.0012	0.0615	0.01%	4.5%
11	FirstEnergy Corp.	$3.00	$2.20	$35.00	26.7%	8.6%	1.0130	8.7%	2.3%	0.0041	0.2222	0.09%	2.4%
12	Great Plains Energy	$2.00	$1.20	$24.75	40.0%	8.1%	1.0143	8.2%	3.3%	0.0016	(0.0102)	0.00%	3.3%
13	Hawaiian Elec.	$2.00	$1.40	$21.00	30.0%	9.5%	1.0494	10.0%	3.0%	0.0644	0.2364	1.52%	4.5%
14	IDACORP, Inc.	$3.65	$1.90	$43.45	47.9%	8.4%	1.0232	8.6%	4.1%	0.0036	0.0853	0.03%	4.2%
15	NV Energy, Inc.	$1.60	$1.05	$18.00	34.4%	8.9%	1.0170	9.0%	3.1%	(0.0001)	0.2653	0.00%	3.1%
16	PG&E Corp.	$3.25	$2.10	$35.50	35.4%	9.2%	1.0255	9.4%	3.3%	0.0251	0.2111	0.53%	3.9%
17	Portland General Elec.	$2.25	$1.30	$26.75	42.2%	8.4%	1.0174	8.6%	3.6%	0.0032	0.0273	0.01%	3.6%
18	PPL Corp.	$2.50	$1.60	$24.25	36.0%	10.3%	1.0454	10.8%	3.9%	0.0436	0.2538	1.11%	5.0%
19	SCANA Corp.	$4.00	$2.25	$41.50	43.8%	9.6%	1.0444	10.1%	4.4%	0.0430	0.2095	0.90%	5.3%
20	Sempra Energy	$5.50	$3.00	$53.00	45.5%	10.4%	1.0251	10.6%	4.8%	0.0091	0.3161	0.29%	5.1%
21	TECO Energy	$1.45	$0.95	$12.00	34.5%	12.1%	1.0122	12.2%	4.2%	0.0006	0.4286	0.03%	4.2%
22	UIL Holdings	$2.55	$1.73	$28.45	32.2%	9.0%	1.0265	9.2%	3.0%	0.0007	0.2888	0.02%	3.0%
23	Westar Energy	$2.60	$1.52	$28.15	41.5%	9.2%	1.0322	9.5%	4.0%	0.0151	0.1338	0.20%	4.2%

DCF MODEL - UTILITY GROUP

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		---------- 2012 ----------			---------- 2017 ----------			Chg	-------- 2017 Price --------				---- Common Shares ----		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2012	2017	Growth
1	ALLETE	56.3%	$2,135	$1,202	57.5%	$2,750	$1,581	5.6%	$55.00	$40.00	$47.50	1.310	39.40	43.50	2.00%
2	Ameren Corp.	49.5%	$13,375	$6,621	49.0%	$15,300	$7,497	2.5%	$40.00	$25.00	$32.50	1.102	242.65	255.00	1.00%
3	American Elec Pwr	49.4%	$30,823	$15,227	54.5%	$35,400	$19,293	4.8%	$60.00	$40.00	$50.00	1.307	485.67	505.00	0.78%
4	Avista Corp.	49.2%	$2,561	$1,260	51.5%	$3,000	$1,545	4.2%	$35.00	$25.00	$30.00	1.250	59.81	64.00	1.36%
5	Black Hills Corp.	56.8%	$2,171	$1,233	48.5%	$3,100	$1,504	4.0%	$45.00	$30.00	$37.50	1.136	44.21	45.20	0.44%
6	CMS Energy Corp.	33.6%	$9,597	$3,225	39.5%	$11,100	$4,385	6.3%	$35.00	$20.00	$27.50	1.719	264.10	274.00	0.74%
7	DTE Energy Co.	51.2%	$14,387	$7,366	50.0%	$19,900	$9,950	6.2%	$75.00	$55.00	$65.00	1.238	172.35	189.00	1.86%
8	Duke Energy Corp.	52.9%	$77,307	$40,895	48.0%	$94,700	$45,456	2.1%	$75.00	$55.00	$65.00	1.012	704.00	710.00	0.17%
9	Edison International	46.2%	$20,422	$9,435	46.5%	$28,200	$13,113	6.8%	$60.00	$45.00	$52.50	1.313	325.81	325.81	0.00%
10	Exelon Corp.	53.5%	$40,057	$21,430	55.5%	$47,100	$26,141	4.1%	$40.00	$25.00	$32.50	1.066	855.00	860.00	0.12%
11	FirstEnergy Corp.	46.3%	$28,263	$13,086	44.5%	$33,500	$14,908	2.6%	$55.00	$35.00	$45.00	1.286	418.22	425.00	0.32%
12	Great Plains Energy	54.4%	$6,136	$3,338	55.0%	$7,000	$3,850	2.9%	$30.00	$19.00	$24.50	0.990	153.53	154.75	0.16%
13	Hawaiian Elec.	53.1%	$3,001	$1,594	51.5%	$5,075	$2,614	10.4%	$30.00	$25.00	$27.50	1.310	97.93	124.50	4.92%
14	IDACORP, Inc.	54.5%	$3,225	$1,758	54.0%	$4,105	$2,217	4.7%	$55.00	$40.00	$47.50	1.093	50.16	51.00	0.33%
15	NV Energy, Inc.	43.2%	$8,227	$3,554	53.5%	$7,875	$4,213	3.5%	$30.00	$19.00	$24.50	1.361	235.08	235.00	-0.01%
16	PG&E Corp.	50.4%	$25,956	$13,082	49.5%	$34,100	$16,880	5.2%	$55.00	$35.00	$45.00	1.268	430.72	475.00	1.98%
17	Portland General Elec.	52.9%	$3,264	$1,727	52.0%	$3,950	$2,054	3.5%	$30.00	$25.00	$27.50	1.028	75.56	76.75	0.31%
18	PPL Corp.	35.9%	$29,205	$10,485	46.0%	$35,900	$16,514	9.5%	$40.00	$25.00	$32.50	1.340	581.94	683.00	3.25%
19	SCANA Corp.	45.6%	$9,103	$4,151	46.5%	$13,925	$6,475	9.3%	$60.00	$45.00	$52.50	1.265	132.00	156.00	3.40%
20	Sempra Energy	46.7%	$22,002	$10,275	46.0%	$28,700	$13,202	5.1%	$90.00	$65.00	$77.50	1.462	242.37	250.00	0.62%
21	TECO Energy	43.5%	$5,265	$2,290	45.0%	$5,750	$2,588	2.5%	$25.00	$17.00	$21.00	1.750	216.60	217.00	0.04%
22	UIL Holdings	41.1%	$2,717	$1,117	45.5%	$3,200	$1,456	5.5%	$45.00	$35.00	$40.00	1.406	50.87	51.00	0.05%
23	Westar Energy	48.8%	$5,938	$2,898	50.0%	$8,000	$4,000	6.7%	$35.00	$30.00	$32.50	1.155	126.50	135.00	1.31%

(a) The Value Line Investment Survey (Mar. 22, May 3, & May 24, 2013).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2017 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2017 BVPS.

EMPIRICAL CAPM - 2013 BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP[1]	Beta	Weight	RP[2]	RP	K_e	Cap	Adjustment	K_e
1	ALLETE	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.70	75%	4.8%	7.1%	10.4%	$ 1,967.6	1.70%	12.1%
2	Ameren Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.80	75%	5.5%	7.8%	11.1%	$ 8,714.2	0.76%	11.9%
3	American Elec Pwr	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.65	75%	4.5%	6.8%	10.1%	$ 23,838.3	-0.37%	9.7%
4	Avista Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.70	75%	4.8%	7.1%	10.4%	$ 1,730.9	1.72%	12.2%
5	Black Hills Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.80	75%	5.5%	7.8%	11.1%	$ 2,179.8	1.70%	12.8%
6	CMS Energy Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.75	75%	5.2%	7.5%	10.8%	$ 7,615.0	0.92%	11.7%
7	DTE Energy Co.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.75	75%	5.2%	7.5%	10.8%	$ 12,355.7	0.76%	11.5%
8	Duke Energy Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.60	75%	4.1%	6.4%	9.7%	$ 50,096.6	-0.37%	9.4%
9	Edison International	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.75	75%	5.2%	7.5%	10.8%	$ 15,867.0	0.76%	11.5%
10	Exelon Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.80	75%	5.5%	7.8%	11.1%	$ 29,745.5	-0.37%	10.8%
11	FirstEnergy Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.75	75%	5.2%	7.5%	10.8%	$ 18,025.1	-0.37%	10.4%
12	Great Plains Energy	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.75	75%	5.2%	7.5%	10.8%	$ 3,693.9	1.14%	11.9%
13	Hawaiian Elec.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.70	75%	4.8%	7.1%	10.4%	$ 2,738.1	1.70%	12.1%
14	IDACORP, Inc.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.70	75%	4.8%	7.1%	10.4%	$ 2,474.4	1.70%	12.1%
15	NV Energy, Inc.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.85	75%	5.9%	8.2%	11.5%	$ 4,849.5	0.92%	12.4%
16	PG&E Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.50	75%	3.5%	5.8%	9.1%	$ 20,345.9	-0.37%	8.7%
17	Portland General Elec.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.75	75%	5.2%	7.5%	10.8%	$ 2,433.8	1.70%	12.5%
18	PPL Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.65	75%	4.5%	6.8%	10.1%	$ 18,627.9	-0.37%	9.7%
19	SCANA Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.65	75%	4.5%	6.8%	10.1%	$ 6,985.4	0.92%	11.0%
20	Sempra Energy	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.80	75%	5.5%	7.8%	11.1%	$ 20,191.0	-0.37%	10.8%
21	TECO Energy	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.85	75%	5.9%	8.2%	11.5%	$ 4,078.1	1.14%	12.6%
22	UIL Holdings	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.70	75%	4.8%	7.1%	10.4%	$ 2,096.6	1.70%	12.1%
23	Westar Energy	2.4%	10.1%	12.5%	3.3%	9.2%	25%	2.3%	0.70	75%	4.8%	7.1%	10.4%	$ 4,241.5	1.14%	11.6%
	Average												10.6%			11.4%
	Midpoint (h)												10.3%			10.8%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Apr. 15, 2012

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Apr. 15, 2013).

(c) Average yield on 30-year Treasury bonds for 2013 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (Oct. 2012); & Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013).

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (Mar. 22, May 3, & May 24, 2013).

(f) www.valueline.com (retrieved May 23, 2013)

(g) *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

(h) Average of low and high values

EMPIRICAL CAPM - PROJECTED BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	ALLETE	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.70	75%	4.3%	6.3%	10.7%	$ 1,967.6	1.70%	12.4%
2	Ameren Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.80	75%	4.9%	6.9%	11.3%	$ 8,714.2	0.76%	12.0%
3	American Elec Pwr	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.65	75%	3.9%	6.0%	10.4%	$ 23,838.3	-0.37%	10.0%
4	Avista Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.70	75%	4.3%	6.3%	10.7%	$ 1,730.9	1.72%	12.4%
5	Black Hills Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.80	75%	4.9%	6.9%	11.3%	$ 2,179.8	1.70%	13.0%
6	CMS Energy Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.0%	$ 7,615.0	0.92%	11.9%
7	DTE Energy Co.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.0%	$ 12,355.7	0.76%	11.7%
8	Duke Energy Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.60	75%	3.6%	5.7%	10.1%	$ 50,096.6	-0.37%	9.7%
9	Edison International	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.0%	$ 15,867.0	0.76%	11.7%
10	Exelon Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.80	75%	4.9%	6.9%	11.3%	$ 29,745.5	-0.37%	10.9%
11	FirstEnergy Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.0%	$ 18,025.1	-0.37%	10.6%
12	Great Plains Energy	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.0%	$ 3,693.9	1.14%	12.1%
13	Hawaiian Elec.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.70	75%	4.3%	6.3%	10.7%	$ 2,738.1	1.70%	12.4%
14	IDACORP, Inc.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.70	75%	4.3%	6.3%	10.7%	$ 2,474.4	1.70%	12.4%
15	NV Energy, Inc.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.85	75%	5.2%	7.2%	11.6%	$ 4,849.5	0.92%	12.5%
16	PG&E Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.50	75%	3.0%	5.1%	9.5%	$ 20,345.9	-0.37%	9.1%
17	Portland General Elec.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.0%	$ 2,433.8	1.70%	12.7%
18	PPL Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.65	75%	3.9%	6.0%	10.4%	$ 18,627.9	-0.37%	10.0%
19	SCANA Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.65	75%	3.9%	6.0%	10.4%	$ 6,985.4	0.92%	11.3%
20	Sempra Energy	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.80	75%	4.9%	6.9%	11.3%	$ 20,191.0	-0.37%	10.9%
21	TECO Energy	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.85	75%	5.2%	7.2%	11.6%	$ 4,078.1	1.14%	12.7%
22	UIL Holdings	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.70	75%	4.3%	6.3%	10.7%	$ 2,096.6	1.70%	12.4%
23	Westar Energy	2.4%	10.1%	12.5%	4.4%	8.1%	25%	2.0%	0.70	75%	4.3%	6.3%	10.7%	$ 4,241.5	1.14%	11.8%
	Average												10.8%			11.6%
	Midpoint (h)												10.5%			11.1%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Apr. 15, 2012

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Apr. 15, 2013).

(c) Average yield on 30-year Treasury bonds for 2013-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (Oct. 2012); & Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013).

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (Mar. 22, May 3, & May 24, 2013).

(f) www.valueline.com (retrieved May 23, 2013)

(g) *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

(h) Average of low and high values

ELECTRIC UTILITY RISK PREMIUM

2013 BOND YIELD

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.79%
(b)	2013 Average Utility Bond Yield	4.75%
	Change in Bond Yield	-4.04%
(c)	Risk Premium/Interest Rate Relationship	-0.4214
	Adjustment to Average Risk Premium	1.70%
(a)	Average Risk Premium over Study Period	3.47%
	Adjusted Risk Premium	**5.17%**
Implied Cost of Equity		
(b)	2013 BBB Utility Bond Yield	5.19%
	Adjusted Equity Risk Premium	5.17%
	Risk Premium Cost of Equity	**10.36%**

(a) Exhibit WEA-7, page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (Oct. 2012); Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013); & Moody's Investors Service at www.credittrends.com.
(c) Exhibit WEA-7, page 4.

ELECTRIC UTILITY RISK PREMIUM

PROJECTED BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.79%
(b)	Projected Average Utility Bond Yield 2013-2017	6.11%
	Change in Bond Yield	-2.68%
(c)	Risk Premium/Interest Rate Relationship	-0.4214
	Adjustment to Average Risk Premium	1.13%
(a)	Average Risk Premium over Study Period	3.47%
	Adjusted Risk Premium	**4.60%**

Implied Cost of Equity		
(b)	Projected BBB Utility Bond Yield 2013-2017	6.55%
	Adjusted Equity Risk Premium	4.60%
	Risk Premium Cost of Equity	**11.15%**

(a) Exhibit WEA-7, page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (Oct. 2012); Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013); & Moody's Investors Service at www.credittrends.com.
(c) Exhibit WEA-7, page 4.

ELECTRIC UTILITY RISK PREMIUM

AUTHORIZED RETURNS

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.36%	6.08%	4.28%
2007	10.36%	6.11%	4.25%
2008	10.46%	6.65%	3.81%
2009	10.48%	6.28%	4.20%
2010	10.34%	5.56%	4.78%
2011	10.30%	5.13%	5.17%
2012	10.15%	4.27%	5.88%
Average	12.27%	8.79%	3.47%

(a) Major Rate Case Decisions, Regulatory Focus, Regulatory Research Associates; *UtilityScope Regulatory Service*, Argus.

(b) Moody's Investors Service.

ELECTRIC UTILITY RISK PREMIUM

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9135753
R Square	0.8346198
Adjusted R Square	0.83015
Standard Error	0.0051907
Observations	39

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005030969	0.005031	186.7268	4.9423E-16
Residual	37	0.000996889	2.69E-05		
Total	38	0.006027857			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0718048	0.002836309	25.31628	5.77E-25	0.06605789	0.0775517	0.06605789	0.077551695
X Variable 1	-0.4214356	0.030840956	-13.6648	4.94E-16	-0.48392524	-0.35894594	-0.48392524	-0.358945937

CAPM - 2013 BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Implied Cost of Equity
1	ALLETE	2.4%	10.1%	12.5%	3.3%	9.2%	0.70	9.7%	$ 1,967.6	1.70%	11.4%
2	Ameren Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.80	10.7%	$ 8,714.2	0.76%	11.4%
3	American Elec Pwr	2.4%	10.1%	12.5%	3.3%	9.2%	0.65	9.3%	$ 23,838.3	-0.37%	8.9%
4	Avista Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.70	9.7%	$ 1,730.9	1.72%	11.5%
5	Black Hills Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.80	10.7%	$ 2,179.8	1.70%	12.4%
6	CMS Energy Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.75	10.2%	$ 7,615.0	0.92%	11.1%
7	DTE Energy Co.	2.4%	10.1%	12.5%	3.3%	9.2%	0.75	10.2%	$ 12,355.7	0.76%	11.0%
8	Duke Energy Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.60	8.8%	$ 50,096.6	-0.37%	8.5%
9	Edison International	2.4%	10.1%	12.5%	3.3%	9.2%	0.75	10.2%	$ 15,867.0	0.76%	11.0%
10	Exelon Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.80	10.7%	$ 29,745.5	-0.37%	10.3%
11	FirstEnergy Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.75	10.2%	$ 18,025.1	-0.37%	9.8%
12	Great Plains Energy	2.4%	10.1%	12.5%	3.3%	9.2%	0.75	10.2%	$ 3,693.9	1.14%	11.3%
13	Hawaiian Elec.	2.4%	10.1%	12.5%	3.3%	9.2%	0.70	9.7%	$ 2,738.1	1.70%	11.4%
14	IDACORP, Inc.	2.4%	10.1%	12.5%	3.3%	9.2%	0.70	9.7%	$ 2,474.4	1.70%	11.4%
15	NV Energy, Inc.	2.4%	10.1%	12.5%	3.3%	9.2%	0.85	11.1%	$ 4,849.5	0.92%	12.0%
16	PG&E Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.50	7.9%	$ 20,345.9	-0.37%	7.5%
17	Portland General Elec.	2.4%	10.1%	12.5%	3.3%	9.2%	0.75	10.2%	$ 2,433.8	1.70%	11.9%
18	PPL Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.65	9.3%	$ 18,627.9	-0.37%	8.9%
19	SCANA Corp.	2.4%	10.1%	12.5%	3.3%	9.2%	0.65	9.3%	$ 6,985.4	0.92%	10.2%
20	Sempra Energy	2.4%	10.1%	12.5%	3.3%	9.2%	0.80	10.7%	$ 20,191.0	-0.37%	10.3%
21	TECO Energy	2.4%	10.1%	12.5%	3.3%	9.2%	0.85	11.1%	$ 4,078.1	1.14%	12.3%
22	UIL Holdings	2.4%	10.1%	12.5%	3.3%	9.2%	0.70	9.7%	$ 2,096.6	1.70%	11.4%
23	Westar Energy	2.4%	10.1%	12.5%	3.3%	9.2%	0.70	9.7%	$ 4,241.5	1.14%	10.9%
	Average							10.0%			10.7%
	Midpoint (g)							9.5%			10.0%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 13, 2012

(b) Weighted average based on growth projections from The Value Line Investment Survey (Dec. 13, 2012), www.yahoo.com (retrieved Jan. 6, 2013), and www.zacks.com (retrieved Jan. 6, 2013).

(c) Average yield on 30-year Treasury bonds for 2013 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Globa Insight, U.S. Economic Outlook at 25 (Oct. 2012); & Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013).

(d) The Value Line Investment Survey (Mar. 22, May 3, & May 24, 2013).

(e) www.valueline.com (retrieved May 23, 2013)

(f) *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

(g) Average of low and high values

CAPM - PROJECTED BOND YIELD

UTILITY GROUP

	Company	(a) Div Yield	(b) Proj. Growth	Cost of Equity	(c) Risk-Free Rate	Risk Premium	(d) Beta	Unadjusted K_e	(e) Market Cap	(f) Size Adjustment	Implied Cost of Equity
		Market Return (R_m)									
1	ALLETE	2.4%	10.1%	12.5%	4.4%	8.1%	0.70	10.1%	$ 1,967.6	1.70%	11.8%
2	Ameren Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.80	10.9%	$ 8,714.2	0.76%	11.6%
3	American Elec Pwr	2.4%	10.1%	12.5%	4.4%	8.1%	0.65	9.7%	$ 23,838.3	-0.37%	9.3%
4	Avista Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.70	10.1%	$ 1,730.9	1.72%	11.8%
5	Black Hills Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.80	10.9%	$ 2,179.8	1.70%	12.6%
6	CMS Energy Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.75	10.5%	$ 7,615.0	0.92%	11.4%
7	DTE Energy Co.	2.4%	10.1%	12.5%	4.4%	8.1%	0.75	10.5%	$ 12,355.7	0.76%	11.2%
8	Duke Energy Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.60	9.3%	$ 50,096.6	-0.37%	8.9%
9	Edison International	2.4%	10.1%	12.5%	4.4%	8.1%	0.75	10.5%	$ 15,867.0	0.76%	11.2%
10	Exelon Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.80	10.9%	$ 29,745.5	-0.37%	10.5%
11	FirstEnergy Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.75	10.5%	$ 18,025.1	-0.37%	10.1%
12	Great Plains Energy	2.4%	10.1%	12.5%	4.4%	8.1%	0.75	10.5%	$ 3,693.9	1.14%	11.6%
13	Hawaiian Elec.	2.4%	10.1%	12.5%	4.4%	8.1%	0.70	10.1%	$ 2,738.1	1.70%	11.8%
14	IDACORP, Inc.	2.4%	10.1%	12.5%	4.4%	8.1%	0.70	10.1%	$ 2,474.4	1.70%	11.8%
15	NV Energy, Inc.	2.4%	10.1%	12.5%	4.4%	8.1%	0.85	11.3%	$ 4,849.5	0.92%	12.2%
16	PG&E Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.50	8.5%	$ 20,345.9	-0.37%	8.1%
17	Portland General Elec.	2.4%	10.1%	12.5%	4.4%	8.1%	0.75	10.5%	$ 2,433.8	1.70%	12.2%
18	PPL Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.65	9.7%	$ 18,627.9	-0.37%	9.3%
19	SCANA Corp.	2.4%	10.1%	12.5%	4.4%	8.1%	0.65	9.7%	$ 6,985.4	0.92%	10.6%
20	Sempra Energy	2.4%	10.1%	12.5%	4.4%	8.1%	0.80	10.9%	$ 20,191.0	-0.37%	10.5%
21	TECO Energy	2.4%	10.1%	12.5%	4.4%	8.1%	0.85	11.3%	$ 4,078.1	1.14%	12.4%
22	UIL Holdings	2.4%	10.1%	12.5%	4.4%	8.1%	0.70	10.1%	$ 2,096.6	1.70%	11.8%
23	Westar Energy	2.4%	10.1%	12.5%	4.4%	8.1%	0.70	10.1%	$ 4,241.5	1.14%	11.2%
	Average							10.3%			11.0%
	Midpoint (g)							9.9%			10.4%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 13, 2012

(b) Weighted average based on growth projections from The Value Line Investment Survey (Dec. 13, 2012), www.yahoo.com (retrieved Jan. 6, 2013), and www.zacks.com (retrieved Jan. 6, 2013).

(c) Average yield on 30-year Treasury bonds for 2013-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (Oct. 2012); & Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013).

(d) The Value Line Investment Survey (Mar. 22, May 3, & May 24, 2013).

(e) www.valueline.com (retrieved May 23, 2013)

(f) *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

(g) Average of low and high values

EXPECTED EARNINGS APPROACH

UTILITY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	10.0%	1.027434	10.3%
2	Ameren Corp.	8.5%	1.012431	8.6%
3	American Elec Pwr	10.0%	1.023666	10.2%
4	Avista Corp.	8.5%	1.02038	8.7%
5	Black Hills Corp.	9.0%	1.019803	9.2%
6	CMS Energy Corp.	13.0%	1.030714	13.4%
7	DTE Energy Co.	9.0%	1.030059	9.3%
8	Duke Energy Corp.	8.0%	1.010572	8.1%
9	Edison International	11.0%	1.032906	11.4%
10	Exelon Corp.	9.5%	1.019864	9.7%
11	FirstEnergy Corp.	8.5%	1.013033	8.6%
12	Great Plains Energy	8.0%	1.014273	8.1%
13	Hawaiian Elec.	9.0%	1.049438	9.4%
14	IDACORP, Inc.	8.5%	1.023189	8.7%
15	NV Energy, Inc.	9.0%	1.017007	9.2%
16	PG&E Corp.	9.0%	1.025482	9.2%
17	Portland General Elec.	8.0%	1.017359	8.1%
18	PPL Corp.	11.0%	1.045399	11.5%
19	SCANA Corp.	9.5%	1.044433	9.9%
20	Sempra Energy	10.5%	1.025061	10.8%
21	TECO Energy	12.0%	1.012211	12.1%
22	UIL Holdings	9.0%	1.02653	9.2%
23	Westar Energy	9.0%	1.032222	9.3%
	Average (d)			**9.7%**
	Midpoint (e)			**10.7%**

(a) The Value Line Investment Survey (Mar. 22, May 3, & May 24, 2013).

(b) Adjustment to convert year-end return to an average rate of return from Exhibit WEA-5.

(c) (a) x (b).

(d) Excludes highlighted figures.

(e) Average of low and high values.

DCF MODEL - NON-UTILITY GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Church & Dwight	$ 62.50	$ 1.12	1.8%
2	Coca-Cola Co.	$ 39.74	$ 1.12	2.8%
3	Colgate-Palmolive	$ 115.70	$ 2.72	2.4%
4	Gen'l Mills	$ 47.54	$ 1.47	3.1%
5	Kellogg	$ 62.81	$ 1.76	2.8%
6	Kimberly-Clark	$ 96.13	$ 3.24	3.4%
7	McCormick & Co.	$ 70.96	$ 1.39	2.0%
8	McDonald's Corp.	$ 98.89	$ 3.08	3.1%
9	PepsiCo, Inc.	$ 77.82	$ 2.21	2.8%
10	Procter & Gamble	$ 77.46	$ 2.25	2.9%
11	Wal-Mart Stores	$ 74.34	$ 1.88	2.5%
	Average			**2.7%**

(a) Average of closing prices for 30 trading days ended Apr. 11, 2013.
(b) The Value Line Investment Survey, Summary & Index (Apr. 12, 2013).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth		
	Company	V Line	IBES	Zacks
1	Church & Dwight	10.0%	11.7%	11.6%
2	Coca-Cola Co.	9.0%	9.0%	8.8%
3	Colgate-Palmolive	10.5%	9.7%	9.1%
4	Gen'l Mills	7.5%	8.0%	7.4%
5	Kellogg	7.0%	7.3%	8.3%
6	Kimberly-Clark	9.5%	7.8%	7.8%
7	McCormick & Co.	8.5%	8.5%	8.4%
8	McDonald's Corp.	8.0%	9.3%	9.3%
9	PepsiCo, Inc.	8.0%	7.3%	7.3%
10	Procter & Gamble	8.5%	7.8%	8.6%
11	Wal-Mart Stores	9.5%	9.0%	9.4%

(a) The Value Line Investment Survey (retrieved Apr. 10, 2013).
(b) www.finance.yahoo.com (retrieved Apr. 11, 2013).
(c) www.zacks.com (retrieved Apr. 11, 2013).

DCF MODEL - NON-UTILITY GROUP

DCF COST OF EQUITY ESTIMATES

			(a)	(a)	(a)
			Earnings Growth		
	Company	Industry Group	V Line	IBES	Zacks
1	Church & Dwight	Household Products	11.8%	13.5%	13.4%
2	Coca-Cola Co.	Beverage	11.8%	11.8%	11.6%
3	Colgate-Palmolive	Household Products	12.9%	12.1%	11.5%
4	Gen'l Mills	Food Processing	10.6%	11.1%	10.5%
5	Kellogg	Food Processing	9.8%	10.1%	11.1%
6	Kimberly-Clark	Household Products	12.9%	11.2%	11.2%
7	McCormick & Co.	Food Processing	10.5%	10.4%	10.4%
8	McDonald's Corp.	Restaurant	11.1%	12.4%	12.4%
9	PepsiCo, Inc.	Beverage	10.8%	10.1%	10.1%
10	Procter & Gamble	Household Products	11.4%	10.7%	11.5%
11	Wal-Mart Stores	Retail Store	12.0%	11.6%	11.9%
	Average (b)		**11.4%**	**11.4%**	**11.4%**
	Midpoint (c)		**11.3%**	**11.8%**	**11.8%**

(a) Sum of dividend yield (Exhibit WEA-10, p. 1) and respective growth rate (Exhibit WEA-10, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION FOR A GENERAL	)	
ADJUSTMENT OF ELECTRIC RATES	)	Case No. 2013-00197
OF KENTUCKY POWER COMPANY	)	

DIRECT TESTIMONY OF

JEFFREY B. BARTSCH

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jeffrey B. Bartsch, being duly sworn, deposes and says he is the Director, Tax Accounting and Regulatory Services for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Jeffrey B. Bartsch

STATE OF OHIO	)	
	)	Case No. 2013-00197
County of FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffrey B. Bartsch, this the 17th day of June, 2013.

Notary Public

NOTARIAL SEAL STATE OF OHIO

PAULINE A LUTZ
NOTARY PUBLIC - OHIO
MY COMM. EXP. 9-12-16

My Commission Expires

DIRECT TESTIMONY OF
JEFFREY B. BARTSCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00197

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DIRECT TESTIMONY OF
JEFFREY B. BARTSCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Jeffrey B. Bartsch. I am the Director of Tax Accounting and Regulatory Support for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), the parent company of Kentucky Power Company (Kentucky Power or Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Business Administration Degree in Accounting from Ohio University in 1979. I am a Certified Public Accountant and have been licensed in Ohio since 1981. I am also a member of the American Institute of Certified Public Accountants. I was first employed by Arthur Andersen & Co. in 1979 in the Audit section where I was assigned to various clients, including those in the electric utility industry. In 1985, I accepted a position with the AEPSC Tax Department. Since that time I have held various positions until June 2000 when I was promoted to my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES?

A. As Director of Tax Accounting and Regulatory Support, my responsibilities include oversight of the recording of the tax accounting entries and records of AEP and its subsidiaries, including Kentucky Power. I am also responsible for coordinating the development of state and federal tax data to be provided by the AEPSC Tax Department in regulatory proceedings. I have attended numerous tax, accounting and regulatory seminars throughout my professional career.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. In addition to previous testimony before the Public Service Commission of Kentucky (Commission), I have filed testimony before the Public Utilities Commission of Ohio on behalf of Columbus Southern Power Company and Ohio Power Company; with the Michigan Public Service Commission on behalf of Indiana Michigan Power Company; with the Louisiana Public Service Commission on behalf of Southwestern Electric Power Company; and with the Federal Energy Regulatory Commission in a transmission rate case for the eastern AEP Operating Companies. I have also filed testimony with and testified before the Public Utility Commission of Texas on behalf of AEP Texas Central Company, AEP Texas North Company, Southwestern Electric Power Company and Electric Transmission Texas, LLC. In addition, I have filed testimony with and testified before the Virginia State Corporation Commission on behalf of Appalachian Power Company, the Public Service Commission of West Virginia on behalf of Appalachian Power Company and Wheeling Power Company and with the Indiana Utility Regulatory Commission on behalf of Indiana Michigan

Power Company. Like Kentucky Power, all of these companies, except Electric Transmission Texas, LLC, are AEP operating companies.

III. PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my testimony in this proceeding is to calculate the Gross Revenue Conversion Factor, to present and support the jurisdictional federal, state and local income taxes to which Kentucky Power is subject, and to support certain fixed, known and measurable ratemaking adjustments to the test year ended March 31, 2013 related to these income taxes including the income tax adjustments related to the proposed transfer to Kentucky Power of an undivided 50% interest in Ohio Power Company's Mitchell generating station. Finally, I will discuss the tax aspects of a change in postretirement benefits (PRB).

IV. GROSS REVENUE CONVERSION FACTOR

Q. PLEASE DESCRIBE THE GROSS REVENUE CONVERSION FACTOR (GRCF).

A. The GRCF represents the factor necessary to determine the incremental amount of gross revenue required to generate an additional dollar of operating income after accounting for the effects of uncollectible accounts, Commission assessment fees and State and Federal income taxes.

Q. HOW WAS THE GRCF RATE DETERMINED?

A. The same methodology was used in this case as was utilized in the Company's prior cases. The uncollectible accounts rate and commission assessment fees rate were provided to me by Witness Wohnhas and the state income tax rates and apportionment factors are based on the most recent state income tax returns filed. I reviewed the potential impact that the transfer of an undivided 50% interest in the Mitchell generating station to Kentucky Power would have on the state apportionment factors and determined that any impact would be minimal. Therefore, I did not revise the effective state income tax rates from those reflected on the most recent state income tax returns that have been filed. Please see Section V, Workpaper S-2, Page 2.

V. <u>JURISDICTIONAL STATE AND FEDERAL INCOME TAXES</u>

Q. PLEASE DESCRIBE THE COMPUTATION OF JURISDICTIONAL STATE AND CURRENT FEDERAL INCOME TAXES.

A. The computation of jurisdictional Current Federal Income Tax is accomplished by first allocating the various items used in the determination of the Company's total separate return federal taxable income, and applying the statutory federal income tax rate of 35%, as shown on workpapers in Schedule 10. The computation of jurisdictional Deferred Federal income tax is accomplished by applying the appropriate federal income tax rate to the allocated normalized timing differences, as shown on workpapers in Schedule 10, and by amortizing the allocated balances of the embedded Deferred Federal income taxes balances over the appropriate remaining lives. The computation of jurisdictional Deferred Investment Tax Credit is accomplished by amortizing the allocated balances over the appropriate remaining lives. The State income tax is calculated on the same basis as the Federal income tax expense as shown in Workpaper S-10. Witness Munsey is responsible for the jurisdictional allocation factors.

Q. WERE DEFERRED TAXES AND INVESTMENT TAX CREDITS ALLOCATED?

A. Yes. Each component was allocated as shown on the workpapers in Schedule 10.

VI. RATEMAKING ADJUSTMENTS

Q. WHICH RATEMAKING ADJUSTMENTS ARE YOU SPONSORING?

A. I am sponsoring ratemaking Adjustments in Section V, Schedule 4, pages 16, 63, 64 and 65 in their entirety and am a co-sponsor for the adjustment on page 59, specifically the accumulated deferred federal income taxes (ADFIT) associated with the Mitchell Plant. I am sponsoring the following ratemaking adjustments:

ADJ	Description	Reference
W16	Deferred Investment Tax Credit	WP S-4, p. 16
W59	Inclusion of Mitchell Plant O&M and Rate Base	WP S-4, p. 59
W63	Removal Cost Schedule M	WP S-4, p. 63
W64	Section 199 Manufacturing Deduction	WP S-4, p. 64
W65	Mitchell Depreciation Schedule M	WP S-4, p. 65

Each of these adjustments is necessary in order to reflect an adjusted test year level of tax expense representative of ongoing operations. In addition, I have reviewed each of the ratemaking adjustments proposed by other Company witnesses and determined the proper income tax consequences as shown on Section V, Schedule 4.

Q. PLEASE DESCRIBE THE TAX ADJUSTMENTS THAT YOU ARE SPONSORING.

A. Adjustment W-16 on page 16 of Schedule 4 adjusts the Deferred Investment Tax Credit (DITC) amortization expense to reflect the proper level of amortization based on the new book depreciation rates which are being recommended in this rate filing by Company witness Davis. Additional detail regarding this adjustment is provided below.

Adjustment W-59 on page 59 of Schedule 4 adjusts the ADFIT as of March 31, 2013 to be included in rate base as a result of the transfer of 50% of the Mitchell Plant to Kentucky.

Adjustment W-63 on page 63 of Schedule 4 adjusts the Removal Cost Schedule M to reflect the average of the deduction claimed on the last three tax returns filed.

Adjustment W-64 on page 64 of Schedule 4 adjusts the Section 199 Manufacturing Deduction that would have been claimed by Kentucky Power had it filed a separate Federal income tax return rather been included in the AEP System Consolidated Tax Return. This adjustment was based on the average of the last three stand-alone tax returns. Additional detail regarding this adjustment is provided below.

Adjustment W-65 on page 65 of Schedule 4 incorporates the depreciation related Schedule M's that need to be considered with regards to the Mitchell Plant transfer. These Schedule M's are based on Kentucky Power's proposed 50% interest in the Mitchell Plant.

<u>Deferred Investment Tax Credit Adjustment (W-16)</u>

Q. WHY IS KENTUCKY POWER PROPOSING A DEFERRED INVESTMENT TAX CREDIT (DITC) ADJUSTMENT?

A. Investment Tax Credits were claimed for eligible property additions on the Federal income tax returns of Kentucky Power starting in the mid-1970's and continuing until the credits were no longer available. Under the tax normalization rules, these credits were deferred and were amortized over the life of the property – generally 30 years – through cost of service or income tax expense under the Company's §46(f)(2) ITC Election. The annual DITC amortization is starting to decrease each year as the DITC vintage deferral years become fully amortized. This is a known and measurable event for the first year Kentucky Power's proposed new rates will be in effect. An adjustment was calculated based on the 12 month period beginning after the new rates are anticipated to go into effect (January 1, 2014). The revised annual DITC amortization amount was based on the unamortized DITC balance as of December 31, 2013 and the new book depreciation rates which are being recommended in this case by Company witness Davis. The effect of this adjustment is to decrease Kentucky Power's jurisdictional DITC amortization by $186,277.

Section 199 Manufacturing Deduction (W-64)

Q. **HAS THE COMPANY REFLECTED THE ANNUAL EFFECT OF THE SECTION 199 DEDUCTION UNDER THE INTERNAL REVENUE CODE IN THE CALCULATION OF THE FEDERAL INCOME TAX OBLIGATION?**

A. Yes. The Company reflected a Section 199 manufacturing deduction in the calculation of the Federal income tax liability in Section V, Schedule 4, Workpaper S-4, page 64 even though Kentucky Power has not been able to claim this deduction since 2006. The Company has not been eligible to take advantage of the Section 199 deduction as a result of its participation in the AEP Consolidated Federal income tax return, however, a Section 199 deduction has been computed for this rate filing as if the Company had filed a separate stand-alone Federal Income Tax Return with the IRS. The Company has utilized this separate stand-alone tax return approach consistently in its tax calculations in previous rate filings with this Commission.

Q. **HOW DID KENTUCKY POWER CALCULATE A SECTION 199 DEDUCTION FOR PURPOSES OF THIS RATE PROCEEDING?**

A. Kentucky Power used a three year average of what its Section 199 deduction would have been on its 2009, 2010 and 2011 Federal income tax returns had it filed separate stand-alone corporate tax returns for those years.

Q. **DOES KENTUCKY POWER EXPECT TO CLAIM A SECTION 199 DEDUCTION ON ITS 2012 OR ITS 2013 TAX RETURN?**

A. At this time it is uncertain whether or not Kentucky Power will actually have positive qualified manufacturing income in 2012 or 2013 in order to receive a Section 199 deduction in either year.

VII. TAX TREATMENT OF MEDICARE PART D REGULATORY ASSET

Q. HAS THE COMPANY PROPOSED AN AMORTIZATION ADJUSTMENT RELATED TO A POSTRETIREMENT BENEFIT REGULATORY ASSET?

A. Yes. The Company has proposed Adjustment W-25 in Section V, Schedule 4, Workpaper S-4, page 25 to amortize this Regulatory Asset over twelve years, as discussed by Company Witnesses McCoy and Mitchell, as a result of the Company's change in retiree prescription drug plans.

Q. PLEASE EXPLAIN THE FACTORS LEADING UP TO THE MEDICARE PART D TAX ACCOUNTING CHANGE AND THE RESULTANT REGULATORY ASSET.

A. The Company historically has included medical and prescription drug costs in its PRB costs. For book purposes, these costs were expensed as accrued and included in cost of service. Because the accrual relates to expected future cash expenditures, the PRB costs are not deductible for tax purposes until paid. Over the years the Company recorded a schedule M add back for the net increase in the PRB accrual. The accrued expense did not result in a current tax benefit. However, a deferred tax asset was recorded and a corresponding credit to income tax expense (tax benefit) was included in cost of service. In 2004, the federal government decided to provide an incentive for companies to continue providing prescription drug benefits to its retirees eligible for Medicare and Congress designated the receipt of the subsidy as tax exempt income to the recipient. The Company created a contra liability account to record the expected subsidy related to the amount accrued in the PRB account described above. The increase in the contra liability account was included as a reduction to the PRB accruals included in cost of service. Because the accrued receipt of the federal subsidy was considered tax exempt, a schedule M deduction was recorded. The reduction in pre-tax expense related to the Medicare subsidy did not result in a current tax cost and no deferred tax liability was recorded. Therefore the ratepayer received the full pre-tax benefit of the federal prescription drug subsidy in the cost of service. In March 2010, Congress retained the tax exempt character of the Medicare Part D subsidy, but disallowed any deduction for prescription drug expenditures reimbursed by the subsidy starting in 2013. The tax impact of the change was to re-characterize a portion of the previously accrued PRB costs as nondeductible. Because those costs were no longer deductible, under ASC 740 the deferred tax asset that had previously benefited ratepayers as a reduction to cost of service and related to the nondeductible portion of the PRB costs was reversed.

Q. ON WHAT BASIS DID THE COMPANY ESTABLISH A REGULATORY TAX ASSET (SFAS 109) FOR THE MEDICARE PART D TAX ACCOUNTING CHANGE?

A. Historically, ratepayers have received the benefit of the deferred taxes related to PRB cost through cost of service as the PRB costs were accrued over several years. The tax benefit associated with the tax exempt federal Medicare subsidy accrued in a contra liability account has also been included in cost of service since its inception. The change in deductibility of the prescription drug expense resulting from the March 2010 tax law change was expected to increase tax costs in the future, which is similar to recapturing the tax benefits that were previously reported as the PRB costs were accrued. The ratepayer was expected to incur the additional tax cost beginning in 2013 on those now nondeductible accrued prescription drug costs. Therefore, in 2010 the Company established an ASC 740 (formerly SFAS 109) regulatory asset in all its regulated jurisdictions to record the expected future recovery of the increased tax cost that was previously reported as a benefit to ratepayers through deferred taxes

Q. WHAT OTHER REASONS SUPPORTED THE RECORDATION OF A REGULATORY ASSET FOR THE NONDEDUCTIBLE MEDICARE PART D COSTS?

A. The Company relied on the Commission's position on regulatory accounting matters in previous regulatory proceedings to conclude that it was probable that the Company would be able to recover the increased tax cost due to the change in tax law. This is consistent to situations where the tax law has changed and the Commission has allowed the recovery of the impact of those tax law changes on future tax expense, like the reduction in federal income tax rates and changes in state tax laws.

Q. WHAT CHANGES HAVE OCCURRED MOST RECENTLY WITH THE COMPANY'S POSTRETIREMENT MEDICAL BENEFITS?

A. As discussed by Company witness McCoy, in 2013 the Company switched from the Medicare Part D Plan to a less costly Employer Group Waiver Plan (EGWP). As a result of this switch to a new plan, the Company will no longer receive a Federal subsidy for providing prescription drug benefits to its retirees and as a result will not have a disallowance of prescription drug expenditures reimbursed by the subsidy. Therefore, there is no tax vehicle (-i.e.- flow-through Schedule M Addback) in which to amortize or reverse the PRB SFAS 109 Regulatory Asset. As a result, the SFAS 109 PRB Regulatory Asset that was associated with the non-deductible prescription drug portion of Accrued PRB costs was transferred to non-tax PRB Regulatory Asset. As discussed by Company witness McCoy, there is significant savings to be realized from the switch to the EGWP Plan and he recommends amortizing this related Regulatory Asset over a 12 year period in order to match the expense from amortizing the Regulatory Asset to the savings to be realized.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION FOR A GENERAL ADJUSTMENT OF ELECTRIC RATES OF KENTUCKY POWER COMPANY	) Case No. 2013-00197

DIRECT TESTIMONY OF

DOUGLAS R. BUCK

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Douglas R. Buck, being duly sworn, deposes and says he is Senior Regulatory Consultant for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Douglas R. Buck
Douglas R. Buck

STATE OF OHIO	)	
	)	Case No. 2013-00197
County of FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Douglas R. Buck, this the 19th day of June, 2013.

Ellen A. McAninch
Notary Public

My Commission Expires: May 11th, 2016

NOTARIAL SEAL STATE OF OHIO

ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Recorded in
Franklin County
My Comm. Exp. 5/11/16

DIRECT TESTIMONY OF
DOUGLAS R. BUCK, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00197

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DIRECT TESTIMONY OF DOUGLAS R. BUCK, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Douglas R. Buck. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I currently hold the position of Senior Regulatory Consultant, Regulated Pricing and Analysis, in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Kentucky Power Company.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT HISTORY.

A. I received my Bachelor of Science Degree in Mechanical Engineering in 1985 from Valparaiso University. I am a Registered Professional Engineer (PE) in Ohio. I received my Master of Business Administration Degree in 1993 from Northern Illinois University. I began my career with AEP in 1997 as a Financial Analyst, Financial Forecasting group, in the Corporate Planning and Budgeting Department. In 2000 I became a Financial Analyst Coordinator, Resource Planning and Operational Analysis group, also in the Corporate Planning and Budgeting Department. In 2006 I became the Director of Enterprise Risk Management in the Risk and Strategic Initiatives Department. I accepted my current position in September 2010. Prior to joining AEP I worked for approximately 9 years in various engineering departments and the Strategic Analysis Department of Commonwealth Edison (now Exelon) in Chicago, Illinois.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony before the Virginia State Corporation Commission regarding cost-of-service related issues.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Kentucky Power Company (Kentucky Power or Company).

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to support the proposed rates designed to produce the base rate revenues requested by the Company. This rate design supports the Company's proposed Tariffs and rates sponsored by Company Witness Munsey.

IV. RATE DESIGN

Q. PLEASE DESCRIBE ANY MAJOR RATE DESIGN CHANGES BEING PROPOSED IN THIS PROCEEDING.

A. No rate design changes are being proposed. For this proceeding rates were designed using the methods applied and approved in the previous Kentucky Power rate case before this Commission, Case No. 2009-00459.

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE COMPANY'S PROPOSED RATES.

A. In general, the Company's approach is to design rates and rate components which reflect the underlying costs of the Company. This includes collecting customer-related costs through customer charges and recognizing the differences in the costs to serve customers at different service delivery voltages. As with the allocation of the revenue increases to the customer classes, the concept of gradualism must be considered in the movement toward full cost-based rate components to avoid undue impacts on customers.

In general, the rate design process involved a number of steps which tended to vary with each tariff. The cost components developed by Witness Stegall provided guidance as to the relative amounts of revenue that should be recovered from customer charges, energy charges and demand charges. First, proposed customer, energy and demand full cost rates were developed for each class by dividing the component-allocated proposed revenues by the test year billing units. These initial rates were then compared to the current rates to determine which price changes would need to be moderated to mitigate price impacts that could cause individual bill impacts that might be considered too severe.

Q. PLEASE SUMMARIZE THE PROPOSED RATES AND ANY PROPOSED RATE DESIGN CHANGES FOR EACH CUSTOMER CLASS.

A. The main components of the rate designs are outlined below. As previously stated, no rate design changes are being proposed. Additionally, proposed rates were designed in an attempt to maintain the purpose for which each tariff is intended.

Residential Service – RS

The standard residential tariff, RS, has a monthly service charge and energy charge. Tariffs RS-TOD and RS-LMTOD are residential time-of-use tariffs with a service charge and separate energy charges for on-peak and off-peak energy consumption. The price difference between the on-peak and off-peak rate has been increased in proposed Tariffs RS-TOD and RS-LMTOD rate design, providing an improved price signal favoring off-peak consumption. Residential customers can also access the same off-peak rate as contained in Tariffs RS-TOD and RS-LMTOD without taking their entire service under the TOD rate, since Tariff RS includes an optional load management water heating provision for residential customers with water-heating systems that normally operate only during off-peak hours. An additional optional load management experimental time-of-day, RS-TOD2, tariff includes a service charge and three distinct energy charges for three time periods, winter on-peak, summer on-peak, and all other hours.

mall General Service – SGS

Tariff SGS is available to small commercial customers with an average monthly peak demand of 10 kW or less taking service at secondary voltage. The standard tariff recovers customer-related costs in a monthly customer charge, and remaining costs through two block energy charges. The first energy block is applicable for up to 500 kWh per month and the second block for all additional kWh taken each month. SGS tariff offers a load management time-of-day provision, SGS-LMTOD, which segments the energy charge into on- and off-peak charges and permits customers that can shift usage to off-peak times to take advantage of a lower cost-based off-peak energy charge. An additional optional load management experimental time-of-day tariff, SGS-TOD, includes a service charge and three distinct energy charges for three time periods, winter on-peak, summer on-peak, and all other hours. This tariff further encourages customers to manage consumption during high cost winter and summer hours.

Medium General Service – MGS

Tariff MGS is a general service rate tariff designed to accommodate medium-sized commercial and industrial ("C&I") loads of variable usage characteristics. The MGS tariff is applicable to customers with average monthly demands between 10 kW and 100 kW.

The MGS tariffs contain voltage delineated charges for customers that take service at secondary and primary distribution voltages, as well as the sub-transmission level. The basic charges recover customer-related costs in a monthly service charge, a two block energy charge, and a demand charge. An additional MGS provision is available for recreational lighting which consists simply of a service charge and an energy charge.

Tariffs MGS-TOD and MGS-LMTOD are time-of-use tariffs with a service charge and separate energy charges for on-peak and off-peak energy consumption. The price difference between the on-peak and off-peak rate has been increased in the proposed tariffs' rate design in order to provide an improved price signal favoring off-peak consumption.

The MGS tariff is designed to recover a smaller percentage of the demand-related costs through the demand charge than tariffs for larger customers such as the Large General Services ("LGS") tariff. MGS rates in the prior rate case, Case No. 2009-00459, collected approximately 9.6% of demand related costs through the demand charge. Proposed MGS rates are designed to collect approximately 11.2% of demand related costs through the demand charge. The remaining demand-related costs are included in the energy charges.

Large General Service – LGS

Tariff LGS is a general service rate tariff designed to accommodate large C&I loads of variable usage characteristics. The LGS tariff is applicable to customers with normal maximum demands between 100 kW and 1,000 kW.

The LGS tariffs contain voltage delineated charges for customers that take service at secondary and primary distribution voltages, as well as the sub-transmission and transmission voltage levels. The basic charges include a service charge, an energy charge, a demand charge, and an excess reactive power charge. This design produces LGS rates that recover a larger percentage of the demand-related costs through the demand charge than tariffs for smaller customers such as the MGS tariff. In the prior and current cases, approximately 21.4% and 23.6%, respectively, of demand related costs are collected through the demand charge. LGS offers a load management time-of-use tariff, LGS-LMTOD, with a service charge and separate energy charges for on-peak and off-peak energy consumption. LGS also offers a time-of-use tariff, LGS-TOD, with a service charge, demand charge, separate energy charges for on-peak and off-peak energy consumption, and an excess reactive power charge.

Quantity Power – QP

Tariff QP is designed to accommodate large C&I customers with demands of less than 7,500 kW and contract capacities not less than 1,000 kW. This tariff recovers nearly all of the demand-related costs through the demand charge and contains voltage delineated charges for customers that take service at secondary and primary distribution voltages, and the sub-transmission and transmission levels. The basic charges include a service charge, an energy charge, an on-peak billing demand and an off-peak excess billing demand charge, and an excess reactive power charge.

Commercial and Industrial - Time-of-Day – CIP-TOD

Tariff CIP-TOD is a full cost tariff designed to accommodate large C&I customers with normal maximum demands of 7,500 kW and above. Costs are recovered through a service charge, an energy charge, on- and off-peak demand charges, and an excess reactive power charge. Each of these charges was set at or very close to the full cost for each component. This tariff also contains minimum demand charges. This tariff contains voltage delineated charges for customers that take service at the primary distribution voltage, and the sub-transmission and transmission levels.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION FOR A GENERAL) ADJUSTMENT OF ELECTRIC RATES) OF KENTUCKY POWER COMPANY)	Case No. 2013-00197

DIRECT TESTIMONY OF

ANDREW R. CARLIN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Andrew R. Carlin, being duly sworn, deposes and says he is the Director, Compensation and Executive Benefits for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Andrew R. Carlin

Andrew R. Carlin

STATE OF OHIO)
) Case No. 2013-00197
County of FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Andrew R. Carlin, this the 24 day of June, 2013.

NOTARIAL SEAL STATE OF OHIO

CURT D. COOPER, ATTORNEY AT LAW
Notary Public, State of Ohio
My Commission has no expiration

Curt D Cooper

Notary Public

My Commission Expires: No expiration

**DIRECT TESTIMONY OF
ANDREW R. CARLIN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

CASE NO. 2013-00197

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DIRECT TESTIMONY OF
ANDREW R. CARLIN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Andrew R. Carlin. My business address is American Electric Power, 15th Floor, One Riverside Plaza, Columbus, Ohio 43215. My position is Director of Compensation & Executive Benefits for the American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Kentucky Power Company (Kentucky Power). AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including Kentucky Power.

Q. PLEASE DESCRIBE YOUR EDUCATION, PROFESSIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Arts Degree from Bowdoin College in 1988 with majors in Economics and Government. I also received a Masters of Business Administration Degree from the J. L. Kellogg Graduate School of Management at Northwestern University in 1992, with concentrations in finance, management strategy, and accounting.

From 1987 to 1988, I worked for Putnam Investor Services as a Shareholder Services Representative. From 1988 to 1990 and in the summer of 1991, I worked as an Associate Consultant and Research Analyst in the U.S. Compensation Practice for William M. Mercer, a leading international human resource consulting firm. From 1992 to 2000, I worked for Bank One Corporation, now part of J.P. Morgan Chase, in multiple planning, finance and compensation capacities.

I joined AEPSC as the Director of Executive Compensation & Benefits in 2000. In 2002 I took on responsibility for employee compensation, in addition to my executive compensation and benefits responsibilities. In my current position, I am responsible for, among other things, developing and maintaining effective and cost-efficient compensation programs for the Company and its subsidiaries.

Q. WHAT SERVICES DOES THE AEPSC COMPENSATION SECTION PROVIDE TO KENTUCKY POWER, AEP AND AEPSC?

A. The compensation section develops and administers compensation programs that are market competitive to enable Kentucky Power, AEP and AEPSC (the Company) to attract and retain employees with the skills and experience necessary to efficiently and effectively operate its business. The compensation section conducts ongoing research and recommends changes to compensation programs as necessary. The compensation section also develops communications materials in support of compensation programs, and monitors compliance with federal and state regulations related to compensation.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in person or submitted written testimony in the following regulatory proceedings:

- On behalf of Kentucky Power Company in Kentucky Case No. 2009-00459;

- On behalf of Appalachian Power Company in Virginia S.C.C. Case No. PUE-2011-00037;
- On behalf of Indiana Michigan Power Company in Michigan Case No. U-16180;
- On behalf of Appalachian Power Company and Wheeling Power Company in West Virginia Case No. 10-0699-E-42T;
- On behalf of Public Service Company of Oklahoma in Oklahoma Cause No. 201000050;
- On behalf of Southwestern Electric Power Company in Texas P.U.C. Docket No. 40443.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to demonstrate that the compensation paid to Kentucky Power employees; Kentucky Power's allocated share of compensation paid to AEPSC employees, and the amount Kentucky Power seeks to include in its cost of service is reasonable, necessary, market-competitive, vital for the attraction and retention of employees with the skills and experience necessary to efficiently and effectively operate Kentucky Power's business, and beneficial to customers. In addition, I will discuss the steps that the Company has taken, in light of economic conditions and the Company's financial situation, to reduce compensation costs and total labor expense.

II. OVERVIEW OF COMPENSATION PRACTICES

Q. WHAT IS THE COMPANY'S OVERALL APPROACH TO COMPENSATION?

A. The Company's compensation strategy for all levels of positions is to provide a target total compensation opportunity (base salary or base rate plus the target value of all incentive compensation) that is, on average, at the median of that provided for similar positions by companies of similar size and scope operating in the region from which the Company needs to attract and retain employees.

Q. WHAT TYPES OF COMPENSATION DOES THE COMPANY GENERALLY PROVIDE TO EMPLOYEES?

A. The Company compensates all employees with both base pay and an annual incentive compensation opportunity. I refer to the sum of these two types of compensation as total cash compensation (TCC) herein. In addition to base pay and annual incentive compensation, approximately 550 positions in the AEP system are provided with a long-term incentive compensation opportunity. I refer to the total compensation opportunity provided to these management and executive positions (TCC plus long-term incentive compensation) as total direct compensation (TDC) herein. For positions that do not typically receive long-term incentive compensation, TCC and TDC are the same. In this testimony "Total Compensation" is used to refer to the definition of compensation that includes all applicable forms of incentive compensation for the positions in question, TCC or TDC, as appropriate.

Q. HOW DO YOU DETERMINE THAT THE COMPANY'S COMPENSATION LEVELS ARE REASONABLE AND MARKET COMPETITIVE?

A. The Company primarily uses compensation surveys to compare its compensation rates and practices to those of other similar companies. Changes to the Company's compensation rates and practices are generally made as needed to maintain competitive compensation for each position relative to these survey comparisons of market competitive compensation. The Company's compensation department participates in or purchases numerous third-party compensation surveys each year which aid in ensuring that the Company's compensation levels are reasonable and market competitive. These surveys provide extensive compensation information for statistically significant samples of incumbents in a wide variety of jobs.

Specifically, the compensation department matches Company positions to the jobs included in these surveys and compares the compensation levels and practices for these positions with those of similar companies for similar positions with similar responsibilities, size and scope. After accounting for any differences in position scope, the compensation department uses market median total compensation, including the target value of all incentive compensation, as the primary compensation benchmark for each position. Salary is also used as a point of comparison for all positions and TCC is also used as a point of comparison for positions for which the Company provides a long-term incentive compensation opportunity. This process for assigning and reviewing salary ranges is consistent with the compensation practices of the majority of electric utilities and other large U.S. companies. The surveys completed and used in this process for the historical test year are listed in EXHIBIT ARC-1 (Compensation Survey List).

Q. WHY IS TOTAL COMPENSATION CHOSEN AS THE PRIMARY POINT OF COMPARISON RATHER THAN BASE SALARY LEVELS?

A. Total compensation is chosen as the primary point of comparison because it includes base salary *and* all statistically significant types of incentive compensation. Survey information shows that annual incentive compensation is a statistically significant and often substantial component of market competitive compensation for nearly every position. Survey information also shows that long-term incentive compensation is a statistically significant and often substantial component of market competitive compensation for high level exempt and executive positions. Therefore, no assessment of market competitive compensation would be complete or valid without including annual incentive compensation for all positions and including long-term incentive compensation for high level exempt professional, managerial and executive positions. The value of any incentive compensation that both the market and the Company provide is also considered in assigning a job grade to each position. Because of this practice, the Company's base pay levels are typically lower than those of companies that provide less or no incentive compensation opportunity.

Q. IS ANY INCENTIVE COMPENSATION PAID BY THE COMPANY INCREMENTAL TO AN ALREADY COMPETITIVE LEVEL OF COMPENSATION PROVIDED TO ITS EMPLOYEES?

A. No. The Company's incentive compensation is not designed to provide compensation in addition to an already market-competitive compensation package and should not be viewed as a bonus. Rather, the Company provides incentive compensation with a target value that is a critical component of a market-competitive total compensation package.

Q. DOES THE USE OF SURVEY MEDIANS AS BENCHMARKS MEAN THAT EMPLOYEE COMPENSATION WILL INVARIABLY BE AT THE MEDIAN?

A. No. The median is used to assign job grades and ranges to each job as described above, but the base pay range for each job extends approximately 22.5 percent above and below the midpoint. Individual base pay rates may fall anywhere within the assigned range depending on individual performance, qualifications and other factors.

Q. DO YOU BELIEVE IT WOULD BE REASONABLE FOR THE COMPANY TO ELIMINATE A PORTION OF ITS INCENTIVE COMPENSATION?

A. No, because this would reduce the total compensation provided by the Company to less than the market competitive range for a substantial number of positions. Paying market competitive compensation enables the Company to attract, retain, and motivate the suitably knowledgeable, experienced and qualified employees it needs to efficiently and effectively provide services to customers, while minimizing overall expense, which is in the interests of all constituents. For example, the compensation expense saved by targeting compensation to less than the market competitive range would likely be more than offset by increased hiring and training expense due to increased employee turnover, as well as lower employee productivity while newer employees learn to perform their jobs safely, efficiently and effectively. This is particularly true for positions that require lengthy apprenticeships to learn the skills needed to work independently and safely, such as Line Mechanics.

Q. HOW ARE BASE SALARIES, EXCLUDING INCENTIVE COMPENSATION AND OVERTIME, DETERMINED FOR SALARIED EMPLOYEES?

A. Base salary offers for salaried positions are made by the Company management within the salary range for the job grade assigned to each position based on the qualifications and experience of the employee relative to the requirements for the position. For jobs with multiple incumbents, the base salaries of other employees in the same position are also a major factor.

The Company also maintains a merit increase program for all salaried positions. The amount budgeted annually for merit increases is established by senior

AEP management based on salary planning surveys, the market-competitiveness of the Company's compensation and the budget dollars available for salary increases. The merit program generally provides an annual salary increase opportunity to salaried employees based on their individual performance. However, due to financial constraints, the merit program was suspended for 2009 as part of an overall salary freeze and constrained to less than the market competitive level for 2010 for all salaried employees. For executives, the merit program was suspended completely for both of these years. The merit program was suspended and constrained in these years due to the Company's financial situation and the extraordinarily difficult economic conditions in its service territories. For 2011 the Company resumed the merit program with 3.2 percent merit budget of salary expense for that period, which was near the market median for such budgets. For 2012 the Company's merit budget was 2.675 percent, which was less than the market median for all employee categories. For 2013, the Company's merit budget was 3.0 percent which was the same as the market median. Since the merit budget was less than the market competitive level for several of these years and since none of these merit budgets were significantly above market, the AEP's pay levels did not keep pace with market competitive compensation during this period.

As part of the merit program, each employee's individual performance is evaluated on at least an annual basis. The amount of the "merit" increase awarded to each employee, if any, is based on a combination of factors, including their individual performance rating, their performance relative to their peers, the position of their salary within the salary range for their job, and the size of the merit budget.

Q. HOW DOES THE COMPANY'S OVERALL BASE SALARY INCREASE BUDGET COMPARE TO MARKET FOR THE YEARS 2009 THROUGH 2013?

A. Table ARC-1 below compares median utility industry base salary increase budgets for employees, other than those in hourly/craft positions, to Company's salary increase budget for the years 2009-2013.

Table ARC-1

	Non-exempt Salaried	Exempt	Executive
Utility Industry Market Median*			
2009 Actual	2.750%	2.500%	2.000%
2010 Actual	2.700%	3.000%	2.950%
2011 Actual	3.000%	2.900%	3.000%
2012 Actual	2.750%	3.000%	3.000%
2013 Projected	3.000%	3.000%	3.000%
Total	14.200%	14.400%	13.950%
The Company			
2009 Actual	0.000%	0.000%	0.000%
2010 Actual	2.000%	2.000%	0.000%
2011 Actual	3.200%	3.200%	3.200%
2012 Actual	2.675%	2.675%	2.675%
2013 Actual	3.000%	3.000%	3.000%
Total	10.875%	10.875%	8.875%
Difference	-3.325%	-3.525%	-5.075%

*The Conference Board Research Report, U.S. Salary Increase Budgets for 2010, 2011, 2012 and 2013

Also shown in Table ARC-1, the Company's base pay increase budgets have substantially lagged the market median overall for the last several years. While many companies pared back their salary increase budgets in 2009 due to economic conditions, the Company's salary freeze was a far more substantial response. While utility companies generally returned to nearly 3 percent increase for 2010, the Company increased base wages by only 2 percent and maintained a salary freeze for executive positions. For 2011, the Company's base wage increases basically kept pace with the market median and did not make up a significant portion of the 2009 and 2010 shortfall. The Company's 2012 salary increase budget of 2.675 percent again lagged the market before returning to market median levels for 2013. Overall, the Company's total salary increase budgets for non-exempt salaried and exempt positions lagged the market median by 3.325 percent and 3.525 percent over this period, while the salary increase budget for AEP executives was a total of 5.075 percent less than the utility industry market median.

Q. HOW ARE BASE PAY INCREASES ADMINISTERED FOR HOURLY/CRAFT EMPLOYEES?

A. Base pay increases for hourly/craft employees, such as line mechanics and meter

Table ARC-2

	Hourly /Craft Employees
Utility Industry Market Median*	
2009 Actual	2.50%
2010 Actual	2.85%
2011 Actual	2.90%
2012 Actual	3.00%
2012 Projected	3.00%
Total	14.25%
The Company	
2009 Actual	0.00%
2010 Actual	2.00%
2011 Actual	3.00%
2012 Actual	2.00%
2013 Projected	2.50%
Total	9.50%
Difference	-4.75%

*The Conference Board Research Report, U.S.

readers, are provided as a general increase, expressed as a percentage of current base pay rates, for all such employees. General increases are negotiated with the labor unions that represent the Company's employees. The Company based its position in these negotiations on survey projections for market median general increases and market median total cash compensation paid by similar companies for these types of positions. As shown in the General Wage Increase Table below, pay increases for these types of employees have also lagged the market overall.

The Company's total increase budget was 4.75 percent less than the market median for hourly/craft employees for the 2009 through projected 2013 period, including a 2.5 percent general increase that has been negotiated with most bargaining units for 2013. Reducing the growth of base wages is one of several difficult steps the Company has taken to address its financial situation and economic conditions in its service territory and this action directly benefits customers by reducing the cost of the Company's electric service.

Q. WHAT OTHER STEPS HAS THE COMPANY TAKEN TO CONTROL COMPENSATION EXPENSE IN LIGHT OF THE GREAT RECESSION AND WEAK RECOVERY?

A. The additional steps the Company has taken include:

- Freezing external hiring from November 2008 through 2009;
- Freezing line of progression promotional increases, such as Accountant II to Accountant I, from November 2008 through 2010, other than for physical/craft positions;
- Substantially reducing the use of external contractors and temporary employees; and
- Substantially reducing the employee workforce through staff reductions and severance programs.

Q. HOW HAVE THE STEPS TAKEN TO CONTROL KENTUCKY POWER, AEP AND AEPSC'S COMPENSATION EXPENSES AFFECTED THE COMPETITIVENESS OF THE COMPANY'S COMPENSATION?

A. The below market merit and base pay increases for 2009 and 2012 caused the Company's base pay, target total cash compensation and target total direct compensation to decline relative to peer companies. As a result, base compensation levels for all types of positions (physical/craft, salaried and managerial) are below the market median on average although the Company's base compensation levels generally remain within the market competitive range (typically +/- 10 percent of the median for hourly/craft employees and +/- 15 percent for other employees). The Company's target annual incentive compensation has also fallen relative to market because these levels are calculated as a function of base compensation. As a result, the Company's target total cash compensation (base pay plus target annual incentive compensation) and target total direct compensation (total cash compensation plus target long-term incentive compensation) were also affected by the steps the Company has taken to control compensation expense, particularly the below market base pay increases.

III. COMPETITIVENESS OF TOTAL COMPENSATION

Q. HOW DOES KENTUCKY POWER, AEP AND AEPSC'S TARGET TOTAL COMPENSATION FOR PHYSICAL AND CRAFT POSITIONS COMPARE WITH MARKET DATA?

A. As shown in EXHIBIT ARC-2 (Kentucky Power TCC vs. Market for Technical, Craft and Clerical Positions), Kentucky Power's average TCC for the physical and craft positions included in the EAP Data Information Solutions, LLC 2011 Energy Technical Craft Clerical Survey is 7.9 percent below the market median. Assuming a market competitive compensation range of +/- 10 percent of the survey median, which is typical practice for such positions, Kentucky Power's average TCC is within but in the lower half of the market competitive range. However, if Kentucky Power's annual incentive compensation were to be excluded, then TCC for 7 of 13 physical/craft positions would fall below the market-competitive range and Kentucky Power's average TCC would fall 3.3 percent below the market competitive range. This shows that the annual incentive compensation paid by Kentucky Power is necessary to maintain the competitiveness of Kentucky Power's compensation for these positions and, thus, is a reasonable and appropriate cost of doing business that cannot be eliminated without an offsetting increase in base pay.

Q. HOW DOES KENTUCKY POWER'S AND AEPSC'S TARGET TOTAL COMPENSATION FOR NON-MANAGERIAL EXEMPT POSITIONS COMPARE WITH MARKET DATA?

A. EXHIBIT ARC-3 (TCC vs. Market for Exempt Positions) compares Kentucky Power's and AEPSC's compensation for non-executive exempt positions to those of similar companies, based on applicable external survey data. Using +/- 15 percent of the market midpoint as the market-competitive range, which is typical for exempt positions, this exhibit indicates that, on average, the Kentucky Power's and AEPSC's target TCC for these positions was 0.3 percent below the market median, which is well within the +/- 15 percent market competitive range. However, if Kentucky Power's and AEPSC's annual incentive compensation were to be excluded, then TCC for these positions would fall to 11.1 percent below the market median. While the Kentucky Power's and AEPSC's average TCC would remain at the low end of the market competitive range, 14 of 38 individual positions (37 percent) would fall below the market competitive range. This shows that the annual incentive compensation opportunity Kentucky Power and AEPSC provide to these positions is necessary to maintain the competitiveness of the their compensation package and is a reasonable cost of doing business that, practically speaking, cannot be eliminated without a corresponding increase in base pay.

Q. HOW DOES KENTUCKY POWER'S AND AEPSC'S TARGET TOTAL COMPENSATION FOR MANAGEMENT AND LEADERSHIP POSITIONS COMPARE WITH MARKET DATA?

A. The Human Resources Committee of AEP's Board of Directors annually engages a nationally recognized, independent executive compensation consulting firm (Pay Governance, LLC was used for 2012), to conduct a compensation study of AEP's management and executive positions. The peer group used for this study consists of companies specifically selected by the Human Resources (HR) Committee to represent the talent markets from which the Company must compete to attract and retain management and executive employees. For 2012, Pay Governance found that average total direct compensation (base salary, annual incentive compensation, and long-term incentive compensation) was within the market-competitive range (+/- 15 percent of the benchmark), although less than the market median. On average, for 39 executive positions, including all executive officers, the Company's base salaries, total cash compensation, and total direct compensation were 6, 5, and 1 percent below market, respectively (see EXHIBIT ARC-4). Accordingly, on aggregate, the Company's total compensation is market competitive, albeit below the market median on average. However, with respect to many positions, total compensation would fall below the market competitive range if the Company did not provide annual incentive compensation or replace it with some other form of compensation. In addition, nearly all of these positions would fall below the market competitive range if long-term incentive compensation was eliminated.

Once again, this shows that the incentive compensation is necessary to maintain the competitiveness of the total compensation package the Company provides to its employees. Therefore, the Company's total compensation, including the full target value of incentive compensation, is a reasonable cost of doing business. Practically speaking, this incentive compensation cannot be eliminated without a corresponding increase in base pay or without diminishing the Company's ability to attract and retain the suitable knowledgeable and experienced management and executive employees that the Company needs to efficiently and effectively provide its services to customers.

IV. TYPES OF INCENTIVE COMPENSATION OFFERED BY THE COMPANY

Q. DO YOU HAVE COMMENTS ABOUT INCENTIVE COMPENSATION TRENDS AND ITS PREVELANCE?

A. Yes. Incentive compensation has withstood the pressures of the great recession and the unprecedented challenges of cost, risk, scrutiny and talent management issues facing employers today. It continues to be used nearly universally by public utilities and other U.S. companies to encourage desired behaviors and provide competitive total compensation opportunities. The compensation analyses discussed above in this testimony (EXHIBITS ARC 2, 3 and 4) show that market median total compensation includes incentive compensation for 100 percent of the positions included in these studies, including all 13 technical, craft and clerical positions, in which 113 Kentucky Power employees are incumbents.

The Company provides both annual and long-term incentive compensation as part of a market-competitive total compensation package, not as a "bonus" on top of an already market competitive compensation package. As a result, incentive compensation does not have any incremental cost, beyond the cost of providing market competitive compensation through base pay alone. In other words, if incentive compensation were not provided, the same dollar value of compensation would need to be added to base pay in order to retain market competitive total compensation. Paying market competitive compensation enables the Company to attract, retain, and motivate the suitably knowledgeable and experienced employees it needs to efficiently and effectively provide its electric services to ratepayers. Furthermore, incentive compensation provides many additional and substantial benefits to ratepayers, which are described in detail later in this testimony.

Q. HOW COMMON ARE ANNUAL INCENTIVE COMPENSATION PLANS IN THE UTILITY INDUSTRY?

A. Annual incentive compensation plans are widespread in U.S. industry and among public electric utility companies. Median actual and target short-term incentive compensation is at least 5 percent of base salary for all levels of salaried energy services industry employees, including positions with base salaries of less than $30,000 (Towers Watson Data Services, 2012 CDB Energy Middle Management, Professional and Support Compensation Survey Report, p. 141). Over 100 Energy Services Industry companies participated in this survey. The Mercer 2011/2012 US Compensation Planning Report indicates that 95 percent of the 1,200 responding companies offer incentive pay to at least some segment of their employee population. Furthermore, EXHIBIT ARC-5 (Towers Watson 2010 Annual Incentive Plan Design Survey Findings Report), states that:

> In today's turbulent economic environment, organizations face a 'perfect storm' of cost, risk, scrutiny and talent management issues. Amid these unprecedented challenges, annual incentive plans continue to play an important role in communicating and reinforcing critical organizational objectives, encouraging desired behaviors and providing competitive total direct compensation opportunities. (p. 4)

Q. **WHAT ARE THE GENERAL BENEFITS OF ANNUAL INCENTIVE COMPENSATION?**

A. The Company provides incentive compensation in lieu of larger base salaries because it improves the Company's performance without increasing overall compensation expense. It encourages cost control and aligns work with Company objectives, thereby increasing both employee and the Company performance. When incentive compensation is provided as a component of a market competitive total compensation package, it has no incremental cost above the cost of providing market competitive compensation using base pay alone.

Without compensation linked to the Company performance, management's compensation would be dependent only on retaining their position, which would reduce investment by discouraging managers from taking on prudent business investments. Such a compensation structure would be misaligned with the interests of both shareholders and customers, who depend on the Company's continued prudent and efficient investment in maintenance, system upgrades and system expansion for electric service. Similarly, linking compensation only to short-term performance is counter to both shareholder and customer interests because it would discourage investment necessary for the long-term success of the business. The age old adage "You get what you pay for" generally rings true with compensation. Paying only base compensation to employees at any level sends a clear signal to them that they need only perform their job well enough to avoid being fired for poor performance. For management employees, the absence of incentive compensation can discourage pursuit of projects that would be prudent investments for shareholders and customers. This is because pursuing major projects requires taking on prudent business risks that puts management's continued employment at risk. Similarly, a management compensation package that includes base pay and only short-term incentive compensation does little to encourage long-term projects, even projects that would be prudent investments for both shareholders and customers, because most long-term projects require upfront investment that reduces short-term earnings and often requires management to forego short-term incentive compensation.

Q. WHAT ADDITIONAL BENEFITS DOES ANNUAL INCENTIVE COMPENSATION PROVIDE?

A. Annual incentive compensation also:

- Helps to attract, retain and motivate the qualified employees the Company needs to efficiently and effectively provide electric service to customers;
- Communicates goals and objectives to employees in a manner that is more effective than otherwise possible. This focuses and more closely aligns employee efforts with these goals and objectives;
- Aligns the goals and objectives of departments throughout the organization with overall goals and objectives and, thereby, better ensure that all groups are working towards the same objectives;
- Encourages and motivates employees to achieve these goals and objectives;
- Rewards employees for their individual performance along with the Company's performance;
- Links some compensation for all employees to performance objectives so that all employees have a personal stake in achieving these objectives;
- Shifts a portion of compensation expense from a fixed to a variable expense that varies based on the performance of the Company. This reduces earnings volatility, business risk, and borrowing costs as well as the difficulties caused by more frequent and extensive changes in the size of the Company's work force that would be necessary without the earnings cushion that incentive compensation provides;
- Creates a culture of high performance and cost consciousness; and
- Reduces the Company's cost of service by virtue of the productivity increases, expense savings, and other benefits that it creates and that the Company would otherwise need to incur additional expense to provide.

A. Annual Incentive Compensation

Q. DESCRIBE THE ANNUAL INCENTIVE COMPENSATION PLANS APPLICABLE TO THIS PROCEEDING.

A. The Company's annual incentive plans cover all employees from hourly positions through executive management. The majority of the goals for Kentucky Power employees participating in this plan are measured at the Kentucky Power (operating company) level. For 2012 there were separate annual incentive plans for Generation; Commercial Operations; Transmission, and several other smaller groups. The remaining employees and all staff function and shared services employees participated in the 2012 AEP Annual Incentive Compensation Plan for the Executive Council and Staff. As in past years, the Company's 2012 annual incentive plans were primarily funded based on AEP's earnings per share (EPS) with an increase or decrease of up to 10 percent based on whether Kentucky Power or any other AEP business unit experienced a work related employee fatality, as shown in EXHIBIT ARC-6 (2012 Company-Wide ICP Measures), page 2-4. Each incentive plan also includes a balanced scorecard consisting of the following four categories of performance measures: Safety and Health, Operational, Financial or Regulatory and Strategic Initiatives. For Kentucky Power in 2012, the financial category consisted of a 10 percent Utility Group operations and maintenance (O&M) vs. budget measure, which is a cost control measure, and a 15 percent Kentucky Power return on equity vs. target measure, which some may consider to be a rate of return measure, but which is really also a cost control measure for companies with regulated rates.

Q. **PLEASE DESCRIBE THE ANNUAL INCENTIVE PROGRAM FUNDING MECHANISM.**

A. As in past years, funding for the annual incentive program for 2012 was tied to AEP earnings per share (EPS) based on a performance measure set by the Human Resources Committee of AEP's Board of Directors (HRC) in consultation with AEP executive management. The HRC and executive management strive to set the EPS performance measure at stretch but achievable levels that support the achievement of AEP's earnings objectives. The EPS performance measure is set at levels that are intended to provide a target payout on average and to only have about a 10 to 15 percent chance of producing either a zero or a maximum payout. In addition to the

EPS measures, the HR Committee also established a fatality adjustment for 2012 that increased or decreased the funding for annual incentive compensation by up to 10 percent depending on whether the Company experienced a fatal work related employee accident.

Q. DESCRIBE THE PERFORMANCE MEASURES IN THE COMPANY'S ANNUAL INCENTIVE PROGRAMS FOR THE TEST YEAR.

A. The balanced scorecard for the 2012 AEP Annual Incentive Compensation Plan for Executive Council and Corporate Staff (see EXHIBIT ARC-7) focused on the following three categories:

- SAFETY - Maintaining the safety of employees, customers and the general public is always a primary consideration, and safety is one of the Company's core values. The safety component of the 2012 scorecard was based on the employee and contractor recordable case rates (measured in accordance with the methodology prescribed by the Occupational Safety and Health Administration) and the employee incident severity rate (measured by the number of lost and restricted duty work days per 200,000 work hours).
- OPERATIONS - This category measures the reliability of our wires assets, the equivalent forced outage rate for our generating plants, NERC reliability compliance, NRC Cornerstone Indicators and our Institute of Nuclear Power Operations (INPO) performance index. The reliability measure was the Company system average interruption duration index (SAIDI), which is the primary and most frequently used measure of reliability by the Company's regulators. The equivalent forced outage rate (EFOR) is an indicator of the extent to which our plants ran reliably during the year.
- STRATEGIC – This category included strategic initiatives related to separating our Ohio generating assets into a separate company, east pool reform, the development of a competitive unregulated business, transmission earnings growth and completion of the first ultra-supercritical coal plant in the U.S.A.

Q. HOW DO THE COMPANY'S INCENTIVE COMPENSATION PLAN TARGETS COMPARE TO OTHER COMPANIES IN TERMS OF THE

PERCENTAGE OF COMPENSATION PAID UNDER THE INCENTIVE PLAN?

A. Taking the Company's annual incentive compensation program as a whole, for 2012 the aggregate of the target awards for all participants was 9.5 percent of participant's base pay, including overtime. This is substantially below both the 16 percent median target for broad based plans [see EXHIBIT ARC-5 (Towers Watson 2010 Annual Incentive Plan Design Survey Findings Report), p.8].

Q. **IS IT APPROPRIATE FOR THE COMPANY TO REQUEST THE TOTAL ANNUAL COMPENSATION COST WHICH INCLUDES THE INCENTIVE PLAN TARGETS INCURRED DURING THE TEST YEAR IN THIS CASE?**

A. Yes. The Company's annual incentive compensation program has been in place for more than 15 years and, as explained further below, the program has produced substantial additional benefits that have already been reflected in the Company's actual expenses for many prior years, including the test year. Because of these benefits, and because the incentive compensation serves only to bring total compensation to market competitive levels it is reasonable for ratepayers to bear the cost of incentive compensation as customers continue to receive its financial benefit through the lower cost of service that efficiencies driven by incentive compensation already provided in the current and prior base rate proceedings.

While the annual incentive program is expected to produce additional incremental benefits going forward, these benefits are likely to be small compared to the cumulative total of all ongoing benefits incentive compensation has produced in past years that have already been captured in rates or will be captured in rates through this proceeding. To the extent that substantial additional benefits are produced going forward, shareholders will pay the expense of the above target portion of the payouts this performance produces, which is appropriate since the financial benefit of this performance improvement would not be captured by customers until the next base rate case, although customers would immediately receive the benefits of any operational improvements. Therefore, as explained in more detail below, it is just and reasonable to include all of the cost of annual incentive compensation in the Company's cost of service for rate making purposes, except for the cost of any above target payouts.

EXHIBIT ARC-8 (CAHRS, *Evaluating the Utility of Performance Based Pay*), page 37, is an academic study that shows the substantial financial benefits that can result from linking pay to performance. The financial benefits shown in this study are the result of improved performance provided by a workforce whose pay was closely linked to performance.

The Company must provide a market competitive total compensation opportunity to efficiently and effectively attract and retain an adequately skilled and experienced workforce. Attracting and retaining such a workforce is necessary for the efficient and effective provision of service to customers and the operation of most aspects of the Company's business. Since the incentive compensation provided by the Company is part of this market competitive total compensation package, it has no incremental cost above the cost of providing market competitive compensation through base pay alone. Therefore, because the Company's annual incentive compensation (a) has no incremental cost to customers; (b) is likely to improve the performance of the workforce over time, as shown by the CAHRS study; and (c) is likely to result in improved operating effectiveness and cost control; it clearly has a substantial overall net benefit to customers.

Eliminating incentive compensation without an offsetting increase in base pay would result in a significant pay cut for all employees and, as previously shown, this would reduce total compensation for a substantial percentage of the Company's positions and employees to below the market-competitive range. Aside from the severe impact this pay cut would have on employee morale, it would reduce employee engagement, reduce productivity and increase employee turnover. This, in turn, would lead to increased hiring and training expense; cause additional reductions in productivity due to the need to train new employees and the considerable time it takes for new employees to acquire the work experience and skills necessary to perform their jobs safely and competently; and, ultimately decrease company performance while increasing overall costs.

Although the compensation that the Company's incentive programs provide could be replaced with additional base pay to achieve a market-competitive total direct compensation package, the loss of the many benefits of incentive compensation would reduce the company's ability to efficiently and effectively provide its electric services to customers. This in turn would lead to escalating costs and declining performance that would negatively impact customers.

Q. IS THE COMPANY REQUESTING THE INCLUSION OF ALL TEST YEAR ANNUAL INCENTIVE COMPENSATION IN ITS REVENUE REQUIREMENT IN THIS CASE?

A. No. The Company is requesting that the O&M expense for the *target* amount of annual incentive compensation for the test year be included in cost of service rather than the actual per books O&M expense. Annual incentive compensation during the test year was actually higher than the target amount due to above target EPS results for 2012. The Company is requesting the normalization of these costs to the target level, which is the amount of annual incentive compensation that the company expects to pay in an average year. It is also the amount of annual incentive compensation that the Company needs to pay, on average, in order to provide market competitive total compensation. The annual incentive compensation amount was adjusted to a target level as supported by Witness Mitchell in Section V, Workpaper S-4, pages 35 and 47.

Q. WHAT ARE THE BENEFITS TO CUSTOMERS OF THE EARNINGS AND OTHER FINANCIAL MEASURES INCLUDED IN THE COMPANY'S ANNUAL INCENTIVE PROGRAM?

A. Tying funding for annual incentive compensation to the Company's earnings and cost control promotes efficient use of financial resources, which is paramount to providing reliable service at a reasonable cost to customers. The earnings and O&M measures included in the Company's incentive compensation programs convey the importance of maintaining financial discipline, and directly encourage employees to reduce expense, operate efficiently, and conserve financial resources. This has and will continue to directly benefit customers by reducing the Company's cost of service through cost savings that are passed on to customers in rates that are lower than they otherwise would if the Company did not use such performance measures.

Since annual incentive compensation expense is significant compared to Kentucky Power's and AEP's earnings, the EPS funding measure also helps ensure that incentive compensation payments do not impair the Company financially. This bolsters the Company's financial stability and reduces its earnings volatility, which benefits customers by reducing its cost of capital and helping to preserve capital during periods of weak earnings. It would be unreasonable to suggest that the Company should not have a mechanism, such as the EPS funding measure, to reduce or eliminate incentive compensation at times when it can ill afford to pay it. This mechanism benefits ratepayers during such times by better balancing the interests of other constituents with those of employees, rather than paying 100 percent fixed compensation to employees and leaving shareholders and ratepayers to absorb all the risk of economic volatility. Thus the EPS funding measure and incentive compensation in general, is a mechanism for balancing the interests of employees, ratepayers and shareholders.

Tying funding for incentive compensation to the Company's financial performance also sends a clear message to all employees that it is imperative for them to control costs and it provides a direct incentive for them to do so. This, in turn, enables the Company to complete work less expensively. Past business unit and staff function performance with respect to O&M expense performance measures shows that, when such incentive plan measures are in place, AEP's business units manage their costs sufficiently to beat even stringent annual O&M budgets when major unbudgeted work additions and reductions are excluded.

Most of such savings have already reduced Kentucky Power's cost of service and rates for Kentucky customers on a dollar for dollar basis through prior base rate proceeding. If only 1 percent of the Company's O&M expense is saved each year due to the incentive compensation program, then millions of dollars per year has been saved by Kentucky customers by virtue of tying incentive compensation to the Company's financial performance measures.

Q. ARE THERE ANY INDIRECT COSTS TO CUSTOMERS OF THE COMPANY'S ANNUAL INCENTIVE PROGRAM?

A. No, there are no indirect costs that offset its benefit to customers. The earnings goals in the Company's annual incentive plan are established with stretch but achievable earnings targets. This ensures that incentive compensation up to target does not encourage company employees to pursue excessive earnings to the detriment of customers. Because the Company is only seeking inclusion of the target value of incentive compensation in its cost of service, the cost of any above target incentive compensation would be born entirely by shareholders. Furthermore, since the Company's revenue is regulated through this and other robust rate case proceedings, the only remaining way for the Company's employees to achieve these earnings objectives is through cost control, which benefits customers. In addition, the balanced scorecard of objectives the Company uses in its annual incentive program help ensure that some measures are not achieved at the expense of other important objectives, such as the safety, operations and environment objectives.

Q. DO THE BENEFITS OF THE COMPANY'S ANNUAL INCENTIVE PROGRAM EXCEED ITS COST FOR KENTUCKY POWER CUSTOMERS?

A. Yes. The Company's incentive compensation program does not increase the Companies' compensation expense beyond that required to provide market-competitive total cash compensation. Therefore, any reduction or elimination of incentive compensation would need to be offset by increases in base pay to maintain market competitive total cash compensation levels. The Company achieves substantial but unquantifiable cost savings through the financial discipline and other benefits that the Company's annual incentive compensation program provides, including reducing the overall cost of service and increasing the dollars available for investment in the maintenance and expansion of the Company's electrical system.

In summary, the Company's annual incentive program provides substantial benefits to customers and has no direct or indirect cost, above the cost of providing market competitive compensation through base pay alone. Therefore, I respectfully submit that it is just and reasonable to include the full cost of the Company's target level of incentive compensation in its cost of service.

B. Long-Term Incentive Compensation

Q. EXPLAIN THE COMPANY'S LONG-TERM INCENTIVE PROGRAM

A. The primary purpose of the Company's long-term incentive program is to encourage managers to make business decisions from a long-term perspective. For 2012 and 2013, the company provided long-term incentive awards in the form of performance units and restricted stock units (RSUs).

Performance units are generally similar in value to shares of AEP common stock, except that the number of performance units that participants ultimately earn is tied to AEP's long-term performance and the participants' satisfaction of vesting conditions over a three-year period. All performance units granted and outstanding in the test year were granted with two equally weighted performance measures: three-year total shareholder return (TSR) measured relative to a peer group of similar utility companies and three-year cumulative EPS relative to a Board-approved target. Both the TSR and EPS measures are capped at reasonable and appropriate levels so that they do not encourage the Company management to pursue these financial objectives at the expense of other objectives, such as safety.

RSUs are also generally similar in value to shares of AEP common stock, except that the number of RSUs that participants ultimately earn is tied to the participants' satisfaction of vesting conditions. Participants who remain employed with AEP through a vesting date receive a share of AEP common stock for each vesting RSU, including dividend equivalent RSUs that have accrued due to reinvested dividends.

Q. IS THE COMPANY REQUESTING THAT LONG-TERM INCENTIVE COMPENSATION EXPENSE BE INCLUDED IN THE COST OF SERVICE IN THIS CASE?

A. The Company is requesting that the target amount of long-term incentive compensation for the test year, be included in its cost of service. The target amount is the normalized cost of long-term incentive compensation that the Company expects to pay on average over time and the amount needed to provide market competitive compensation to management employees The long-term incentive expense target amount is included in Section V, Work paper S-4, pages 35 and 47 and supported by Witness Mitchell.

Q. IS THE LONG-TERM INCENTIVE PROGRAM REASONABLE AND NECESSARY TO EFFECTIVELY AND EFFICIENTLY SUPPORT RELIABLE ELECTRIC SERVICE?

A. Yes. The Company's long-term incentive compensation is a substantial component of the compensation for management employees and is critical to maintaining the market-competitiveness of compensation for such employees. The Company's long-term incentive compensation is not incremental to an already market-competitive level of total direct compensation, and any reduction of this type of compensation would need to be offset by increases in other types of compensation in order to maintain the Company's ability to attract and retain the suitably skilled and experienced employees it needs to efficiently and effectively provide its electric service to customers. A large majority of public companies of AEP's size and complexity have similar programs, as do a large majority of public utility companies. The Pay Governance Market Competitive Compensation Analysis (EXHIBIT ARC-4) shows that long-term incentive compensation is a substantial component of market competitive compensation for 100 percent of the 39 positions included in this analysis. Towers Perrin, a leading compensation consulting firm, reports that 99 of 102 companies that participated in their 2009 Energy Services Executive Compensation Survey have long-term incentive programs for top management employees.

Q. WHAT ARE THE DIRECT BENEFITS TO CUSTOMERS OF THE COMPANY'S LONG-TERM INCENTIVE PROGRAM?

A. As with annual incentive compensation, tying long-term incentive compensation to financial performance measures promotes the efficient use of financial resources, which is paramount to providing reliable service at a reasonable cost. Maintaining long-term financial discipline is imperative for the Company, its shareholders and its customers. The EPS and TSR measures associated with the performance units granted as part of the long-term incentive plan communicate this and strongly encourage its continued pursuit by tying a substantial portion of the compensation for management and executive employees to both internal and external measures of the Company's long-term financial performance. This encourages these employees to reduce expense, operate efficiently, and conserve financial resources, which directly benefits customers by keeping rates low.

Tying funding for long-term incentive compensation to AEP's earnings also retains additional capital in the company during periods of weaker earnings performance, which bolsters the Company's financial stability and provides more capital for system maintenance during periods in which other sources of capital may be overly expensive or inaccessible. My discussion above regarding the benefits of reduced earnings volatility is also one of the benefits of long term incentive compensation. Tying long-term compensation to the Company's financial performance sends a clear message to participants that it is imperative for them to maintain financial discipline and it provides a direct incentive for them to do so. This, in turn, enables the Company to complete work less expensively. As with annual incentive compensation, if the long-term incentive program results in only a 1 percent annual O&M expense savings, then millions of dollars per year has been saved by Kentucky customers by virtue of this program.

Q. ARE THERE ANY INDIRECT COSTS TO CUSTOMERS FOR THE COMPANY'S LONG-TERM INCENTIVE PROGRAM?

A. No. AEP's long-term incentive goals are established at stretch but achievable targets. This ensures that customers are not paying for long-term incentive compensation that may encourage company employees to generate excessive earnings. The Company is only seeking inclusion of the target value of long-term incentive compensation in its cost of service, so the cost of any above target long-term incentive compensation payments would be born entirely by shareholders, not customers.

The goals in the Company's long-term incentive plan are also balanced by the scorecard goals in the annual incentive plan to assure that the EPS and TSR goals are not achieved at the expense of other important objectives. As with annual incentive compensation, any increase in long-term incentive compensation that might be achieved by reducing spending in operations areas, for example, would likely be at least partially offset by a decrease in annual incentive funding due to the decline in the operating performance scores. As a result of this balanced approach to incentive compensation, AEP's long-term incentive compensation does not encourage behaviors that would be counter to customers' interests and there are not any significant indirect costs that would offset the benefits of long-term incentive compensation to customers.

Q. DO THE TOTAL BENEFITS OF THE COMPANY'S LONG-TERM INCENTIVE PROGRAM EXCEED ITS COST TO KENTUCKY POWER CUSTOMERS?

A. Yes. Similar to annual incentive compensation, the Company provides long-term incentive compensation as part of a market-competitive total direct compensation package. Therefore, the Company's long-term incentive compensation does not have an incremental cost to customers, beyond the cost of providing a market competitive total direct compensation package through other types of compensation. As with annual incentive compensation, the long-term incentive program has been in place for many years, so its accumulated ongoing benefits are already reflected in the Company's expense for the test year and incorporated into rates in prior rate proceedings. It is not appropriate for shareholders to pay the cost of maintaining long-term incentive compensation from which customers have already captured the financial benefit through a lower cost of service that is reflected in this and prior rate proceedings. While the long-term incentive program is expected to produce an additional marginal benefit going forward, this additional benefit is likely to be small and incremental compared to the benefit created to date. To the extent that the long-term incentive program produces additional benefits going forward, shareholders will pay for the incremental incentive expense associated with the above target performance, which is appropriate since the financial benefit of this performance would not be passed on to customers until the next base rate case.

V. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY WITH RESPECT TO COST RECOVERY FOR COMPENSATION EXPENSE.

A. The design of the Company's compensation programs and, specifically, its annual and long-term incentive compensation programs, are reasonable and appropriate from the customer's perspective. These programs are necessary to ensure that the Company is able to attract, retain, and motivate the employees needed to efficiently and effectively provide electric service to its customers. The compensation that the Company provides, including annual and long-term incentive compensation, is a just, reasonable and prudent cost of doing business. This compensation is market competitive on a base pay, target total cash compensation, and target total direct compensation basis. Annual and long-term incentive compensation is provided as part of this overall market-competitive compensation package and does not represent an incremental expense to Kentucky Power's ratepayers. Therefore, I respectfully submit that it is just and reasonable to include the full cost of the Company's compensation, including the target level of both annual and long-term incentive compensation, in the Company's cost of service.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT ARC -1 (Compensation Survey List)

Surveys Complete and Used for Compensation Comparisons During the Historical Test Year

Towers Watson U.S. Compensation Data Bank (CDB):

- 2012 Energy Services Industry, Executive
- 2012 Energy Services Industry, Middle Management, Professional and Support
- 2012 General Industry, Executive
- 2012 General Industry, Middle Management, Professional and Support
- 2012 Custom AEP Peer Group, Executive

Mercer U.S. Benchmark Database:

- 2011 Finance, Accounting and Legal
- 2011 Human Resources
- 2011 Mercer/Gartner Information Technology Compensation Survey

Aon Hewitt Total Compensation Measurement (TCM) Online U.S

- 2012 Executive All Companies
- 2012 Executive Energy Services Peers

Aon 2010 Energy Marketing and Trading Compensation Survey

EAPDIS, LLC, 2012 Energy Technical Craft Clerical Survey

WorldatWork 2011-2012 Salary Budget Survey

The Conference Board, U.S. Salary Increase Budgets for 2012

EXHIBIT ARC-2 (KYPO Target TCC vs. Market for Technical, Craft and Clerical Jobs)

KYPO Target Total Cash Compensation (Target TCC) vs.
2012 EAPDIS Energy Technical, Craft & Clerical Survey (Southeast Region Data)

Survey Job	AEP Title	EEs	Base[1]	Target Annual Incentive[2]	Target TCC	ETC&C Survey Median Base[3]	ETC&C Survey Median Incentive	ETC&C Survey Median TCC	% Difference AEP TCC vs. Survey TCC	% Difference AEP Base vs. Survey TCC
Line Mechanic (OH/UG)	Line Mechanic-A	35	$64,955	$3,248	$68,203	$70,289	$1,591	$71,880	-5.4%	-10.7%
Storekeeper/Handler	Storekeeper	1	$57,200	$2,860	$60,060	$56,689	$3,098	$59,787	0.5%	-4.5%
Substation Mechanic/Technician	Station Electrician A	5	$65,732	$3,287	$69,019	$69,610	$2,567	$72,177	-4.6%	-9.8%
Motor Vehicle Mechanic	Fleet Technician A	4	$62,733	$3,137	$65,870	$64,857	$4,180	$69,037	-4.8%	-10.0%
Meter Mechanic	Meter Electrician-A	4	$65,083	$3,254	$68,337	$68,082	$2,397	$70,480	-3.1%	-8.3%
Meter Reader	Meter Reader	2	$30,264	$1,513	$31,777	$45,657	$2,058	$47,715	-50.2%	-57.7%
Trouble Shooter Mechanic	Line Servicer	25	$66,581	$3,329	$69,910	$76,462	$127	$76,590	-9.6%	-15.0%
Control Operator	Unit Operator	8	$67,218	$3,361	$70,579	$74,808	$1,931	$76,738	-8.7%	-14.2%
Certified Welder	Maintenance Welder	9	$67,746	$3,387	$71,133	$70,904	$3,204	$74,107	-4.2%	-9.4%
Instrument and Control Tech	Control Technician-Sr	4	$67,746	$3,387	$71,133	$70,522	$4,540	$75,062	-5.5%	-10.8%
Plant Machinist	Maintenance Machinist	1	$65,770	$3,289	$69,059	$65,473	$3,734	$69,207	-0.2%	-5.2%
Coal Yard Equipment Operator	Coal Equipment Operator-Sr	7	$65,770	$3,289	$69,059	$64,921	$3,076	$67,997	1.5%	-3.4%
Plant Equipment Operator	Equipment Operator	8	$58,490	$2,925	$61,415	$64,815	$1,909	$66,724	-8.6%	-14.1%
	Total	113						Average	-7.9%	-13.3%
								% of Jobs Above Market Competitive Range[4]	None	None
								% of Jobs Below Market Competitive Range[4]	8%	54%

Notes

(1) As of April 23, 2013

(2) The Company's target payout is 5 percent of base earnings for all physical and craft jobs

(3) Annualized from April 2012 to April 2013 @ 2.0% salary growth rate

(4) A market competitive range of +/- 10 percent has been used for all physical and craft positions

EXHIBIT ARC-3 (TCC vs. Market for Exempt Positions)										
Compensation Survey Analysis- Exempt Positions										
									% Difference AEP	% Difference AEP
		EE	AEP Incumbent Data			Survey Results[1]			Total Comp vs	Base vs Survey
Survey Job	AEP Title	Count	Avg Base	Incentive [(2)]	Total Comp	Base	Incentive	Total Comp	Survey Total Comp	Total Comp
KYPO Positions [(3)]										
Energy Delivery/Distribution-Career Level	Distr Dispatcher I	4	$86,068	$8,607	$94,675	$88,230	$12,240	$100,470	-6.1%	-16.7%
Energy Delivery/Distribution Supervisor	Supv Distribution System	3	$97,780	$9,778	$107,558	$98,430	$7,752	$106,182	1.3%	-8.6%
Fossil Power Generation Operation-Supervisor	Energy Production Supv III	4	$87,565	$8,757	$96,322	$93,636	$9,894	$103,530	-7.5%	-18.2%
Fossil Power Generation Operation-Manager	Energy Production Supv II	5	$100,668	$10,067	$110,735	$113,832	$17,034	$130,866	-18.2%	-30.0%
Fossil Power Generation Operation-Sr Manager	Energy Production Supt II	1	$131,346	$19,702	$151,048	$124,644	$31,212	$155,856	-3.2%	-18.7%
Fossil Power Generation Maintenance-Supervisor	Maintenance Supv III	3	$88,607	$8,861	$97,468	$93,636	$8,670	$102,306	-5.0%	-15.5%
Fossil Power Generation Maintenance Planning-Specialist Level	Long Range Planner	1	$98,223	$9,822	$108,045	$94,656	$11,220	$105,876	2.0%	-7.8%
Fossil Power Generation Fuel Yard-Manager	Material Handling Supt I	1	$95,293	$9,529	$104,822	$108,834	$22,644	$131,478	-25.4%	-38.0%
Engineer-Intermediate Level	Engineer III	2	$69,450	$4,862	$74,312	$75,378	$6,018	$81,396	-9.5%	-17.2%
Engineer-Career Level	Engineer I	6	$93,548	$9,355	$102,903	$94,146	$6,936	$101,082	1.8%	-8.1%
Engineer-Specialist Level	Senior Engineer	1	$116,539	$17,481	$134,020	$110,976	$9,588	$120,564	10.0%	-3.5%
Environmental, Health and Safety: Industrial Hygiene-Career Level	Sr Indtrl Hygnst Consultant	1	$98,034	$9,803	$107,837	$94,554	$3,060	$97,614	9.5%	0.4%
Environmental, Health and Safety: Health/Safety-Manager	Safety & Health Manager	1	$110,525	$16,579	$127,104	$120,870	$20,502	$141,372	-11.2%	-27.9%
Financial Analysis and Tax: Insurance Risk-Career Level	Senior Claims Adjustor	1	$88,018	$8,802	$96,820	$82,212	$3,366	$85,578	11.6%	2.8%
AEPSC Human Resources [(4)]										
HR Manager	Human Resources Manager	6	$120,063	$18,009	$138,072	$102,396	$11,458	$113,854	17.5%	5.2%
HR Generalist - Senior	HR Representative Sr	3	$73,733	$7,373	$81,106	$83,750	$7,292	$91,042	-12.3%	-23.5%
Managerial Professional Recruiter	Recruiter-Senior	2	$78,330	$7,833	$86,163	$84,375	$4,792	$89,167	-3.5%	-13.8%
Labor Relations Manager	Mgr Labor Relations & EEO	4	$131,625	$22,376	$154,001	$126,563	$14,167	$140,729	8.6%	-6.9%
									2.6%	-9.8%
AEPSC Business Logistics [(3)]										
Purchasing Manager	Mgr Procurement	2	$128,072	$21,772	$149,844	$115,158	$16,626	$131,784	12.1%	-2.9%
Facilities Sr Manager	Region Mgr Workplace Svcs	4	$132,431	$26,486	$158,917	$144,636	$16,830	$161,466	-1.6%	-21.9%
Purchasing -Career Level	Buyer/Analyst I	2	$66,562	$4,659	$71,221	$79,866	$5,508	$85,374	-19.9%	-28.3%
Materials Management-Career Level	Material Coordinator	2	$76,640	$7,664	$84,304	$81,702	$11,628	$93,330	-10.7%	-21.8%
AEPSC Information Technology [(4)]										
Database Analyst/Programmer Senior	IT Database Analyst Senior	9	$108,038	$16,206	$124,244	$102,083	$6,250	$108,333	12.8%	-0.3%
Applications Systems Analyst/Programmer - Senior	IT Systems Analyst II	14	$83,038	$8,304	$91,342	$88,542	$6,771	$95,313	-4.3%	-14.8%
Applications Systems Analyst/Programmer - Staff Specialist	IT Software Developer-Sr	30	$101,715	$15,257	$116,972	$102,604	$8,542	$111,146	5.0%	-9.3%
Systems Administrator - Intermediate	IT System Administrator III	5	$67,076	$4,695	$71,771	$75,625	$2,188	$77,813	-8.4%	-16.0%
Business Process Consultant	Sr IT Business Systems Analyst	15	$100,194	$15,044	$115,238	$99,271	$4,792	$104,063	9.7%	-3.9%
Applications Systems Analyst/Programmer - Staff Specialist	Sr IT Systems Analyst	30	$99,595	$14,939	$114,534	$102,604	$8,542	$111,146	3.0%	-11.6%
AEPSC Accounting/Finance/Audit/Legal [(4)]										
Accountant - Senior	Sr Accountant	13	$75,674	$7,567	$83,241	$70,521	$4,167	$74,688	10.3%	1.3%
Accountant - Intermediate	Accountant III	13	$51,615	$2,581	$54,196	$56,354	$1,354	$57,708	-6.5%	-11.8%
Accountant - Associate	Accountant IV	3	$46,400	$2,320	$48,720	$47,813	$1,146	$48,958	-0.5%	-5.5%
Auditor - Senior	Audit Consultant	2	$89,170	$8,917	$98,087	$76,563	$3,957	$80,520	17.9%	9.7%
Tax Accountant - Senior	Tax Analyst I	5	$78,120	$7,812	$85,932	$77,813	$3,958	$81,771	4.8%	-4.7%
Tax Accountant - Associate	Tax Analyst IV	1	$53,500	$2,675	$56,175	$52,083	$1,771	$53,854	4.1%	-0.7%
Financial Analyst - Senior	Sr Financial Analyst	4	$95,975	$9,598	$105,573	$76,250	$4,583	$80,833	23.4%	15.8%
Credit Analyst - Senior	Analyst II CRM	2	$61,388	$4,297	$65,685	$72,917	$5,104	$78,021	-18.8%	-27.1%
Legal Assistant (Paralegal) - Intermediate	Paralegal II	4	$50,097	$2,505	$52,602	$55,417	$833	$56,250	-6.9%	-12.3%
	Incumbent Count	209						Average	-0.3%	-11.1%
Notes:										
(1) All survey data aged to April 2013 at 2% annual rate										
(2) Reflects annual target incentive payout for job						% of Jobs Above Market Competitive Range[5]			7.9%	2.6%
(3) Survey Data from April 2012 Towers Watson Energy Services MMAP (Middle Management & Professional) Su						% of Jobs Below Market Competitive Range[5]			10.5%	36.8%
(4) Survey Data From March 2011 US Mercer Benchmark Database (Revenue >= $10B)										
(5) A market competitive range of +/- 15 percent has been used for all exempt positions										

American Electric Power

Competitive Executive Compensation Analysis

Confidential DRAFT
For Discussion Purposes Only

October 17, 2012

Pay Governance
Advisory Services to Compensation Committees

Exhibit ARC-4
Page 1 of 5

Pay Governance
Advisory Services to Compensation Committees

Introduction

- Pay Governance conducted a competitive compensation assessment of selected executive positions for American Electric Power (AEP)
  - A total of 39 executive positions were included in our analysis
- Consistent with prior analyses, competitive compensation levels were developed primarily based on a peer group of utility and general industry companies
  - A listing of the peer companies is provided on page 3
- Broader energy and general industry data from Towers Watson's Energy Services and General Industry Compensation Databases were used where peer group data were not available

Pay Governance
Advisory Services to Compensation Committees

Methodology

- Competitive "going rates" were developed based on Towers Watson's 2012 Executive Compensation Databases for the following elements of pay:
  - Base salary
  - Target total cash compensation (base salary plus target annual incentive)
  - Target total direct compensation (target total cash compensation plus the fair value of long-term incentives)
- Pay Governance's going rates represent the compensation level provided to a hypothetical, seasoned performer in a position with similar responsibilities and scope
  - Pay Governance typically considers compensation *within 15 percent* (above or below) of going rates to be in the competitive range for executive positions
    - Any variances from the market within this range can typically be explained by experience, time in position, internal equity considerations, and performance
  - Pay Governance's going rates are based on external competitive data and *do not incorporate AEP's internal equity considerations*

Exhibit ARC-4
Page 3 of 5

Pay Governance
Advisory Services to Compensation Committees

Competitive Peer Group

Utility Industry Companies (n=14)

- CenterPoint Energy, Inc.
- Dominion Resources, Inc.
- Duke Energy Corporation
- Edison International
- Entergy Corporation
- Exelon Corporation
- FirstEnergy Corp.
- NextEra Energy, Inc.
- PG&E Corp.
- PPL Corporation
- Public Service Enterprise Group Inc.
- Sempra Energy
- Southern Company
- Xcel Energy Inc.

General Industry Companies (n=12)

- 3M Co.
- Bristol-Myers Squibb Co.
- Caterpillar Inc.
- CSX Corp.
- Goodyear Tire & Rubber Co.
- Northrop Grumman Corporation
- PPG Industries Inc.
- Schlumberger Limited
- Sunoco, Inc.
- Textron Inc.
- Union Pacific Corporation
- Weyerhaeuser Co.

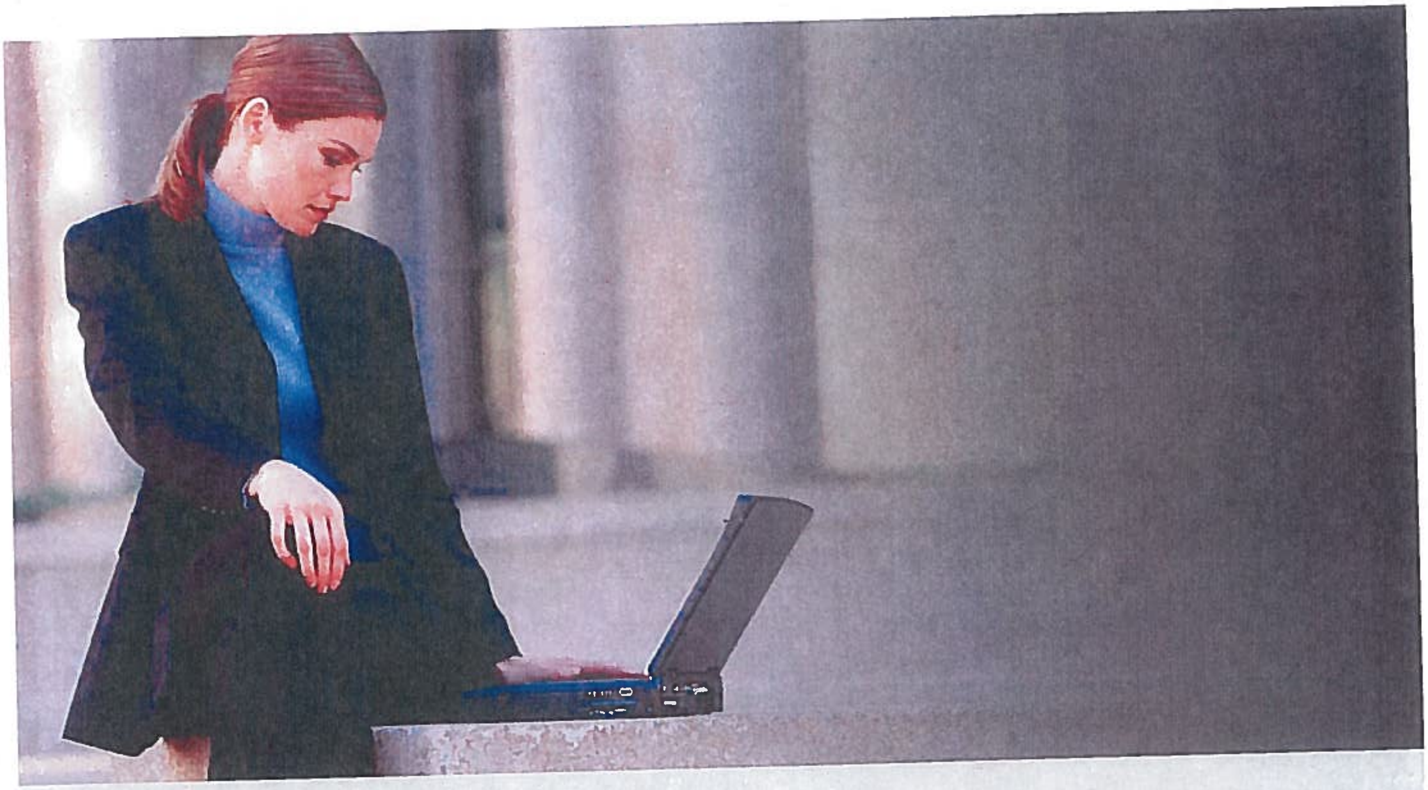
Exhibit ARC-4
Page 4 of 5

Pay Governance
Advisory Services to Compensation Committees

Summary Results

- While AEP's position versus market varies on a position-by-position basis, we note the following overall findings:
  - In the aggregate, AEP's current base salaries are approximately **six percent below** target market
  - AEP's target total cash compensation levels (current base salary plus current target annual incentive) are, on average, **five percent below** target market
  - Overall, AEP's target total direct compensation levels (target total cash as described above plus current long-term incentive levels) remain within the competitive range at approximately **one percent below** target market on an aggregate total direct compensation basis

Exhibit ARC-4
Page 5 of 5



2010 Annual Incentive Plan Design

Survey Findings Report

TOWERS WATSON

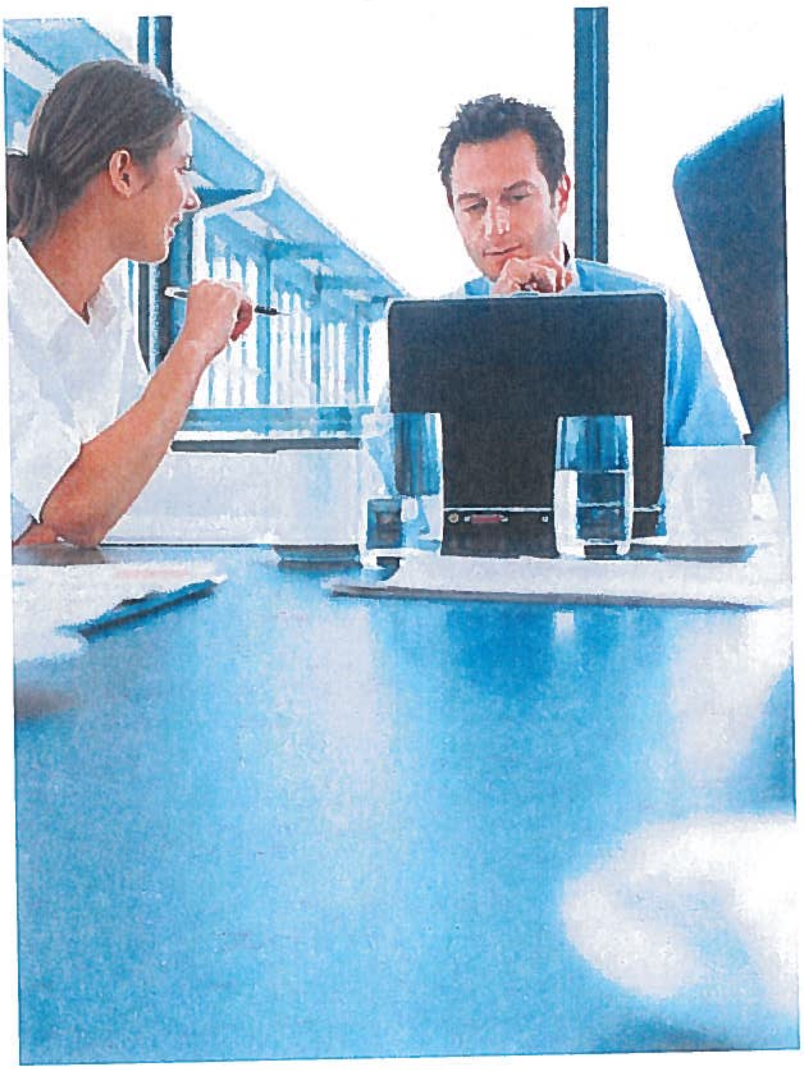
Key incentive plan changes clients have either discussed or implemented include:

- Discretionary awards, possible adjustments to plan metrics and associated communications
- Additional/new metrics (e.g., focus on expense management, use of capital)
- Broader performance ranges, through lower thresholds
- More emphasis on individual objectives
- More ongoing communication to help build employee line of sight

To help companies ensure that their annual incentive plans provide competitive reward opportunities and remain effective in supporting key business and talent goals, Towers Watson conducts ongoing research in annual incentive plan design and operations. Our latest survey of annual incentive plan practices highlights the continuing evolution in plan design, along with some emerging trends in plan management.

2010 Annual Incentive Plan Design

Survey Findings Report



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Overview

In today's turbulent economic environment, organizations face a "perfect storm" of cost, risk, scrutiny and talent management issues. Amid these unprecedented challenges, annual incentive plans continue to play an important role in communicating and reinforcing critical organizational objectives, encouraging desired behaviors and providing competitive total compensation opportunities.

As economic uncertainty continues to cloud the picture, Towers Watson's work with clients during 2009 and the first quarter of 2010 confirms that many pay interventions introduced in response to the current financial crisis have been temporary and tactical, rather than strategic.

Among most companies, decisions about cost still predominate, but the importance of weighing short- and long-term implications is growing. Given that financial and operational results are below historical norms, annual incentive compensation plans are under pressure to respond. But whether adjustments to overall plan design are warranted or have occurred is unclear.

Against this backdrop, Towers Watson's latest survey of annual incentive plan design practices has uncovered some areas where changes have occurred and others where previous plan designs remain the same.

The Towers Watson 2010 Annual Incentive Plan Design Survey is based on a profile of 212 large companies (see Appendix on page 19 for survey participant data). This survey provides detailed information about how organizations based in the U.S. and Canada design annual incentive plans for their top executives. U.S. companies represent 83% of the sample, and Canadian companies represent 17%. Although additional companies can and have joined the survey, the results in this report are based on participants as of December 1, 2009. Towers Watson first conducted the Annual Incentive Plan Design Survey in 1996, following up in 2001 and 2005.

Current plan design practice data are presented, by section, in the remainder of this report of survey findings. Highlights of key trends, developments and changes are organized into three groups:

1. Trends identified in our 2005 survey that remain stable and/or have expanded in practice/prevalence in 2010:

- There is continuing consistency in incentive plan designs within organizations, reflected by the finding that more companies are altering eligibility requirements and offering a single annual incentive plan for executives and other employees.
- Companies continue to be thoughtful about the specific definition of earnings used to measure performance, with relatively less use of earnings per share (EPS) and greater use of earnings before interest and taxes (EBIT or EBITDA) and operating earnings in their annual incentive plans.
- Most companies use two or more performance measures in their annual incentive plans, and the use of sales/revenue as a performance measure has maintained high prevalence.
- There is continued use of a broader and more complex range of performance measures to improve measurement and line of sight.
- Incentive zones and associated payout ranges remain largely unchanged over the past 10 years.
- There is a continued decrease in the use of voluntary deferred compensation arrangements, as companies have adjusted to the additional 409A restrictions that took effect in 2005.

> "There is continued use of a broader and more complex range of performance measures to improve measurement and line of sight."

2. Practices identified as emerging/evolving in 2005 that have not taken a firm hold in the market and/or have retreated in 2010:

- The movement away from thresholds and maximum performance levels to mark the bottom and upper limits of bonus payout zones has not occurred.
- Tying target bonus opportunities to peer group or market is a near-universal practice, and the trend away from this approach, as reported in 2005, has reversed.
- In some areas, the use of discretion in annual incentive plan design remains steady. There has not been significant growth in this practice and, in some areas, the use of discretion has decreased. These findings suggest that even in the midst of economic uncertainty — and often increased pressure to exert more discretion — companies have not made significant changes in this area.

3. New approaches in designing annual incentive plans:

- Plan costs — spending on annual incentive plans as a percentage of net income or revenue — are mostly aligned with data collected in 2005, except that actual spending for the most recently completed year (as of October-November 2009) was below target and historical levels. In addition, actual spending for the current/ongoing year is generally expected to be 20% to 30% below target.
- Plan funding — the method used to determine aggregate spending — has seen continued growth in the use of financial results-based funding formulas; the most prevalent funding measures are cash flow and operating income (versus net income in 2005).
- While the number of performance measures used has not changed and there have been small adjustments to the overall list of measures, there has been an increase in the prevalence of cash flow and EBIT/EBITDA.
- The use of individual performance as a weighted measure has been stable for the CEO position at about one-third prevalence, and has increased from one-third to about half for positions below the CEO level.
- In addition to using individual performance, companies are showing increased use of measures at group/sector and business unit/division levels. Companies appear to be willing to increase the complexity and differentiation within the plans in exchange for greater line of sight and linkages to performance.
- The area of setting performance expectations has changed, with a majority of companies currently basing goals on "expected business conditions." In the past, this method was used less frequently and was less common than goal setting based on budgeted performance and year-over-year growth or improvement. This trend may be a temporary reaction to the current economic environment, or it may continue into the future.

Eligibility

This study focuses on annual incentive plans that include the highest level of corporate management, typically the CEO and the company's senior management group. Over the past decade, a majority of companies have shifted away from offering an executive-only annual incentive plan and separate plans for other employees. Today, most companies offer an annual incentive plan to both executives and employees below the executive level.

All the surveyed plans are grouped into the following categories, according to the types of eligible participants:

- **Top-level executive plans** cover only the CEO, direct reports to the CEO and second-tier executives (i.e., direct reports to the CEO's direct reports) — 13% of the sample.
- **Middle management and above plans** cover not only the CEO and senior executives, but also middle managers — 25% of the sample.
- **Broad-based plans** typically extend to certain professional and administrative employees in addition to the CEO, other senior executives and middle management — 62% of the sample.

Continuing a trend started in 2005, a majority of the surveyed plans fall into the category of broad-based plans. In 2001, over half of the surveyed plans were top-level executive plans. An increasing number of companies align their incentives across the organization, most likely to encourage greater consistency of focus and effort.

"An increasing number of companies align their incentives across the organization, most likely to encourage greater consistency of focus and effort."

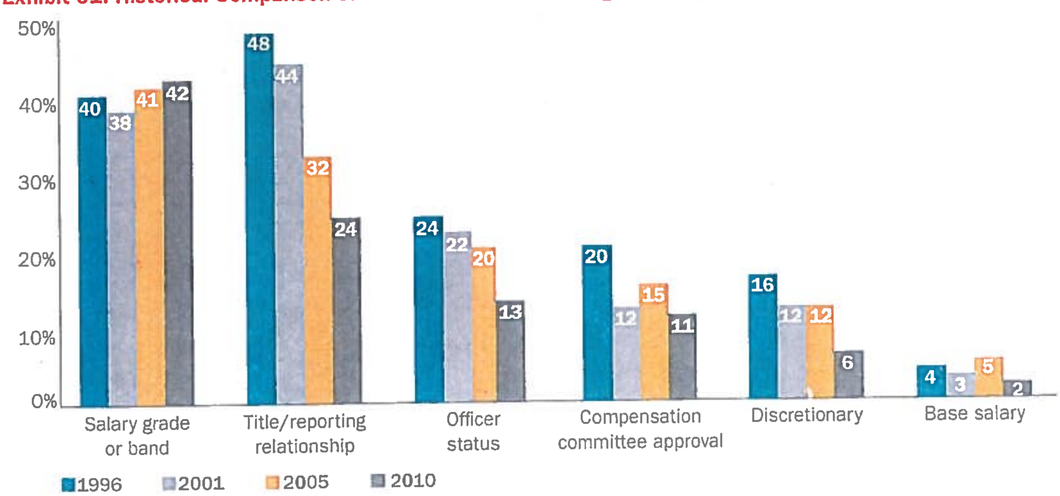
The number of plan participants, as a percentage of total employees, varies by the type of plan:

- **Top-level executive plans** — 0.4% of total employees at the median
- **Middle management and above plans** — 3.1% of total employees at the median
- **Broad-based plans** — over half of these plans include all (or all nonunion) employees in the company; of the broad-based plans that do not include all employees, the median participation is 20% of total employees

Eligibility Criteria

Eligibility to participate in an incentive plan is determined at each company by one or more factors *(Exhibit 1)*. In the 2010 survey, the most common factor for determining eligibility is an employee's salary grade or band. This differs from prior years, when position title, reporting relationship or officer status was a more common factor used to determine incentive plan eligibility. This finding is consistent with the trend toward including employees at various levels in the organization in one plan. In the past, when most survey plans were top-level executive plans that included only the CEO, direct reports to the CEO and their direct reports, an employee's reporting relationship was a simple, straightforward identifier of role and contribution. With plans now extending further into the organization, a more rigorous, contribution-based system (such as salary grades or bands) is used to determine eligibility.

Exhibit 01. Historical Comparison of the Basis for Determining Plan Eligibility



Plan Costs

Incentive plan costs are always a challenging issue for companies as they seek to strike a balance between cost management and competitive bonus levels that will motivate top performance. Given these pressures, often made more intense by heightened executive pay-level scrutiny by shareholders, analysts and the media, companies are carefully monitoring the cost of incentives.

In the 2010 survey, we collected information that allows us to summarize costs for the most recently completed fiscal year (both actual and target) and the current/ongoing fiscal year at target. Across all plans and comparison approaches, reflecting recent economic challenges among participants, actual plan costs are below target levels. These figures may not reflect the total costs of incentives for the companies, because costs may be incurred under other incentive plans not reported in this survey. However these figures do provide a comparison point against which to judge incentive spending.

One insightful way to assess plan costs is to compare the cost of an incentive plan in a given year to the net income generated by the company in that year. The percentage of net income spent on a particular incentive plan is a function of, among other things, how many people participate in the plan, the measures used for incentive purposes and the size of the organization.

Median Plan Cost as % of Net Income

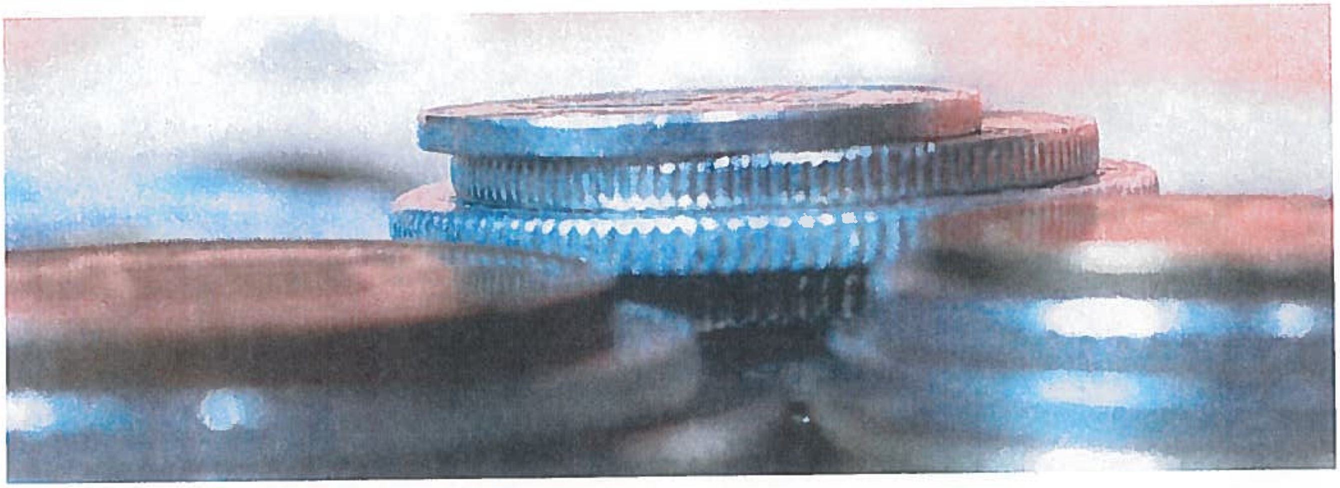
In this year's survey, the portion of net income spent on incentive plans at all three levels is relatively closely aligned with the data in the 2005 survey, except for the actual most recent fiscal-year costs.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	Most Recent Fiscal Year — Actual	Current/Ongoing Fiscal Year — Target	Most Recent Fiscal Year — Actual
Top-level executive plans	1.9%	1.9%	1.7%	2.9%
Middle management and above plans	4.9%	2.8%	5.3%	5.5%
Broad-based plans	6.9%	5.0%	7.1%	6.9%

Median Plan Cost as % of Revenue

Incentive plan costs as a percentage of company revenue provide an indication of how incentives relate to the size of the organization, with 2010 results similar to 2005 results.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	Most Recent Fiscal Year — Actual	Current/Ongoing Fiscal Year — Target	Most Recent Fiscal Year — Actual
Top-level executive plans	0.14%	0.12%	0.16%	0.13%
Middle management and above plans	0.29%	0.17%	0.34%	0.37%
Broad-based plans	0.63%	0.44%	0.69%	0.64%



Median Plan Cost as % of Aggregate Base Salaries of Participants

It is important to evaluate the amount spent on incentives in relation to the aggregate base salaries of employees in the plan. Not surprisingly, top-level executive plans pay out the highest percentage of the aggregate base salaries of plan participants.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	Most Recent Fiscal Year — Actual	Current/Ongoing Fiscal Year — Target	Most Recent Fiscal Year — Actual
Top-level executive plans	41%	36%	41%	44%
Middle management and above plans	27%	24%	28%	32%
Broad-based plans	16%	12%	16%	17%

Plan Costs for Current/Ongoing Fiscal Year

Since the survey data were collected during October-November 2009, we asked participants to report the anticipated/estimated plan costs for the current/ongoing fiscal year (generally, the 2009 fiscal year). This was a new data point in the survey and was not reported by a majority of participants. While we cannot report statistics similar to the plan cost tables above, we conclude that actual spending for the current/ongoing year is generally expected to be in the range of 20% to 30% below target.

Plan Funding

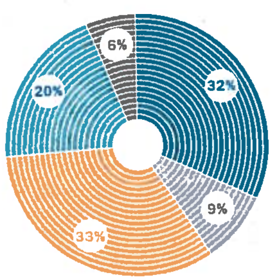
The method used to determine the aggregate size of an incentive pool from which all incentives will be paid plays an important role in achieving a fair balance between the interests of shareholders and plan participants.

Under the *sum-of-targets approach*, the aggregate amount of awards to be paid under the plan in a given year is determined by adding the target awards of all participants. The *sum-of-actual-awards method* is similar, except that actual awards are aggregated rather than target awards. Although over half of the survey plans use one of these approaches, the *financial results-based approach* has shown an increase in comparison to 2001 and 2005 survey findings.

Financial Results-Based Formula

As noted, the use of a funding formula based on financial results, which applies specific financial objectives designed to strengthen the link to company performance, is becoming more prevalent. Almost one-third (32%) of the survey respondents reported using this approach, compared to only 13% of companies in 2001 *(Exhibit 2)*.

Exhibit 02. How Incentive Funding Is Determined



Companies that use this method will either create a bonus fund equal to a percentage of a financial measure (e.g., 3% of net income) or a percentage of a financial measure that exceeds a hurdle rate (e.g., 5% of net income in excess of an 8% return on net assets).

The most common performance measures used for plan funding are operating income and cash flow. Net income and pretax income are also used frequently *(Exhibit 3)*. In 2005, net income was the most common measure, and in 2001 EPS was the most commonly used measure in financial results-based formulas.

Exhibit 03. Measures Used in Incentive Plans With a Financial Results-Based Plan Funding Approach

	2010 Survey*	2005 Survey
Operating income	29%	21%
Cash flow	28%	20%
Net income	22%	25%
Pretax Income	22%	16%

*Percentages total more than 100% due to multiple responses.

Almost one-half of companies that use a financial results-based formula allocate funds to business units based on performance (e.g., a corporate funding pool is allocated to business units based on business unit performance). The remaining companies are relatively evenly split between allocating at an individual level without first allocating to the business unit level and requiring business units to generate their own award pools.

When it comes to plan funding, it is less common to use a purely discretionary approach to determine the aggregate amount of award money (one unrelated to any established formula). For example, the board or management might look at the year's results and decide the company can afford to pay a total of $10 million in bonuses. Nine percent of companies reported using this approach in 2010, up from 5% in 2005, likely due to the difficulty of budgeting and setting performance expectations in the current economic environment.

"The use of a funding formula based on financial results, which applies specific financial objectives designed to strengthen the link to company performance, is becoming more prevalent."

Measuring Performance

In the drive to improve measurement and make compensation practices more effective, organizations continue to adjust their annual incentive plans by altering design features, usually in ways that are important to individual participants but don't involve a wholesale redesign. While cost is always a consideration for employers sponsoring these plans, typical design changes are made with an eye toward improving the line of sight between individual behavior and the organization's business objectives.

Consistent with our 2001 and 2005 findings, nearly nine out of 10 companies (89%) rely on two or more performance measures. Two-thirds of survey respondents (66%) reported that they currently use three or more performance measures.

While sales or revenue is the single most common annual incentive financial performance measure, four of the next five most common measures are earnings- or profit-based, and cash flow is now tied as the second-most prevalent performance measure (*Exhibit 4*, and *Exhibit 5* on page 11). Performance measures that show the largest increases in prevalence, compared to 2005, are cash flow and EBIT/EBITDA. The combination of sales or revenue with the other most common financial measures suggests that the drive for profitable growth is as strong as ever.

Use of Nonfinancial Performance Measures

Nonfinancial performance measures are often considered effective leading indicators of shareholder value creation and continue to gain in popularity (*Exhibit 6*, page 11). Due to the increasing prevalence of these measures, we have captured a wider range of metrics and categories.

Individual Performance and the Level of Performance Measurement

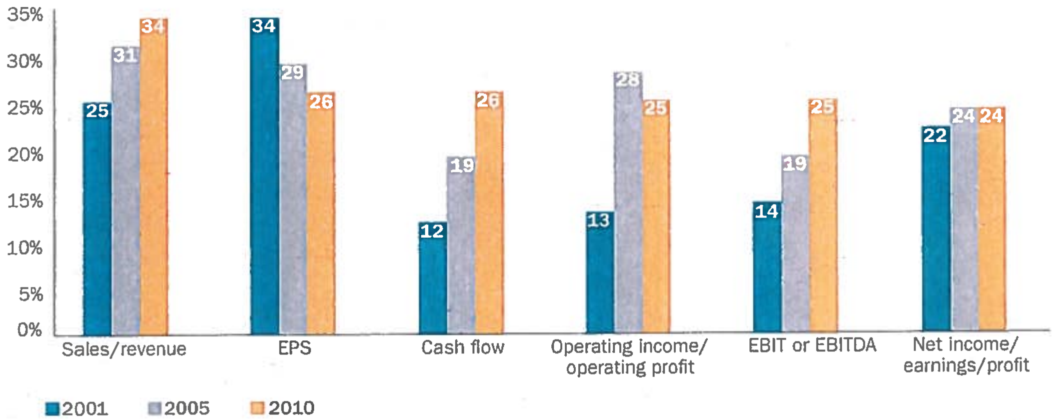
We asked survey participants to report the level at which performance is measured. While some organizations measure performance for the entire company, others measure performance at lower levels. In the latter approach, these companies possibly consider performance for each business unit or division, for the group (which includes several business units or divisions) and/or at the individual performance level.

Exhibit 04. Prevalence of Financial Performance Measures

	2010 Survey	2005 Survey
Sales/revenue	34%	31%
EPS	26%	29%
Cash flow	26%	19%
Operating income/operating profit	25%	28%
EBIT or EBITDA	25%	19%
Net income/earnings/profit	24%	24%
Cost/expense control/reduction	17%	—
Return on investment/return on invested capital (ROI/ROIC)	8%	7%
Return on equity (ROE)	7%	9%
Operating measures (e.g., operating margin)	7%	12%
Pretax income	5%	7%
Working capital	4%	—
Economic profit/economic value added (EP/EVA)	4%	3%
Gross margin	4%	—
Return on assets/return on net assets (ROA/RONA)	3%	4%
Total shareholder return	3%	—
Net operating profit after tax (NOPAT)	2%	—

Percentages total more than 100% due to multiple responses.

Exhibit 05. Historical Comparison of Most Prevalent Financial Performance Measures



A majority (61%) of the surveyed companies measure the CEO solely on corporate performance. In those cases where the CEO's award is based on more than corporate performance, it is usually based on a combination of corporate and individual performance. In short, the two most common CEO performance weightings and combinations are:

- 100% corporate performance
- 80% corporate, 20% individual performance

At lower levels in the organization, it is most common to base awards on two or more levels of performance. Performance measurement for non-CEOs generally depends on the employee's level within the organization.

At the group/sector executive level, common weightings and combinations are:

- 100% corporate performance
- 50% corporate, 50% individual performance
- 50% corporate, 50% group/sector performance

Common weightings and combinations for top business unit or division executives are:

- 25% corporate, 75% business unit/division performance
- 25% corporate, 25% business unit/division, 50% individual performance

Compared to our findings in 2005 and 2001, an increasing number of companies assign a specified weight to individual performance, especially below the CEO level *(Exhibit 7)*. When an individual performance component is included in the CEO's measurement calculation, which is used in 32% of the sample, it is typically assigned a weight of 20%. Individual performance is used below the CEO level by about half of companies, and the typical weighting is 50% of the total incentive opportunity.

Exhibit 06. Prevalence of Nonfinancial Performance Measures

	2010 Survey	2005 Survey
Strategic objectives	27%	—
Safety/environmental	17%	—
Customer satisfaction	16%	14%
Team/department objectives	16%	—
Volume/production	7%	—
Employee satisfaction	4%	4%

Exhibit 07. Level of Performance Measurement

	% of Organizations Using Measures at Each Level			
	Corporate Measures	Group/ Sector Measures	Business Unit/Division Measures	Individual Measures
CEO	93%	—	—	32%
Corporate staff	92%	13%	5%	55%
Top group/sector executive	85%	46%	—	42%
Group/sector staff	47%	79%	—	67%
Top business unit/ division executive	52%	15%	71%	49%
Business unit/ division staff	38%	5%	65%	52%

Calculating the Award

Companies that use more than one performance measure must define how these measures will be combined to calculate an individual's bonus. There are three principal approaches:

- The most common method is the *additive approach,* which calculates performance separately for each measure and then adds the associated incentive awards to determine the final award. The prevalence of this approach is 69% and is consistent with prior survey results.
- 16% of respondents use a *multiplicative method* to calculate individual awards, representing an increase over our 2005 and 2001 results. Under this approach, performance under one measure is adjusted by performance under another measure. For example, a bonus calculated on EPS growth is multiplied by a factor based on a second performance measure to determine the bonus award.
- Similar to 2005 and 2001, fewer than 10% of respondents use the *matrix approach,* in which the levels of performance for two separate measures are each assigned an axis on a matrix. The employee's annual award, usually expressed as a percentage of the target amount, is determined by the intersection of the performance levels for the two measures.

"Similar to our previous findings, the use of circuit breakers and/or modifiers was reported by approximately one-third of respondents."

Circuit Breakers

When several measures are used to calculate bonuses, employees generally do not have to meet all the measures to receive some level of bonus. Some plans designate one or more measure(s) as a "circuit breaker" that essentially requires the achievement of a certain minimum level of performance to receive any award payout. Similar to our findings in 2005 and 2001, plans with some sort of circuit-breaker feature were reported by about one-third of respondents. The four most common corporate performance measures used as a circuit breaker, in order of prevalence, are EPS, EBIT or EBITDA, operating income and cash flow. Individual performance is used as a circuit-breaker measure among 9% of companies. For example, some plans are structured so that, no matter how well the company performs, an individual will not receive any bonus unless his or her performance is at least at some threshold level.

Modifiers

Some plans incorporate a final adjustment to the award calculation by applying a modifier. For example, an otherwise determined award can be increased or decreased by a certain percentage based on how well a certain goal is achieved. While this might be similar to the multiplicative approach, typically the modifier makes a smaller adjustment to a calculated award (e.g., an award calculated using the additive approach is modified by 105% if the modifier goal is achieved).

This practice is reported by 30% of survey respondents, versus 20% in 2005. Most often, this modification is based on an individual performance rating. Other common modifiers are EBIT or EBITDA and sales/revenue.

Performance Incentive Zones and Bonus Payout Ranges

The *performance incentive zone* describes the range of performance outcomes for which incremental increases in performance will result in incremental increases in bonus awards. Some plans place no hard limits on performance that can earn a bonus, creating unlimited upside opportunities. Other plans have thresholds and maximums, creating an incentive zone that represents all possible performance levels between the floor and the maximum or cap.

The *bonus payout range* describes the actual dollar amount that can be earned at each level in the performance incentive zone. Like performance incentive zones, payout ranges can be uncapped if there is no maximum. *Exhibit 8* shows an example of an 80% to 120% performance incentive zone, tied to a bonus payout range of 50% to 200% of target bonus. As this example illustrates, an employee in this plan would receive no bonus for performance up to 80% of target and could not earn more than 200% of his or her target bonus even if performance exceeded 120% of target performance.

The size of performance incentive zones and bonus payout ranges varies considerably among survey participants. The median performance incentive zone for most measures is 40%. In other words, the difference between threshold performance as a percentage of target and maximum performance as a percentage of target is 40%. For example, if the performance threshold is 80% of target, the maximum would be 120% of target.

The median bonus payout range is 150% for most performance measures, indicating a payout range, for example, of 50% at the threshold level of performance and 200% at the maximum level of performance.

The 2010 findings regarding performance incentive zones and bonus payout ranges are consistent with our 2005 and 2001 results. This suggests that companies are comfortable with the leverage inherent in their existing plans.

In previous years, performance incentive zones and bonus payout ranges varied slightly according to the performance measure evaluated. In 2010, the median incentive zones and payout ranges were generally the same for all of the most prevalent performance measures. *Exhibit 9* shows slight differences in the median ranges reported for sales/revenue, EPS, cash flow, operating income/operating profit, EBIT or EBITDA, and net income/earnings/profit.

Exhibit 08. Sample Performance Incentive Zone

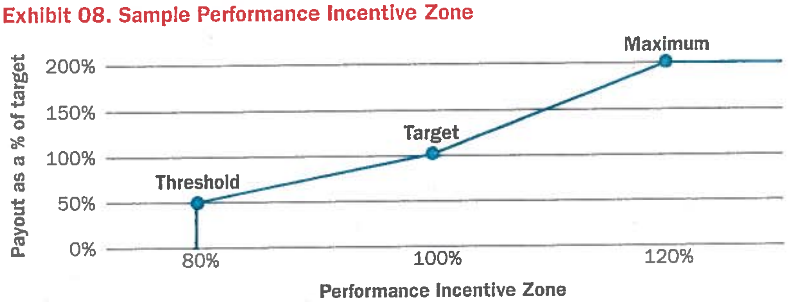
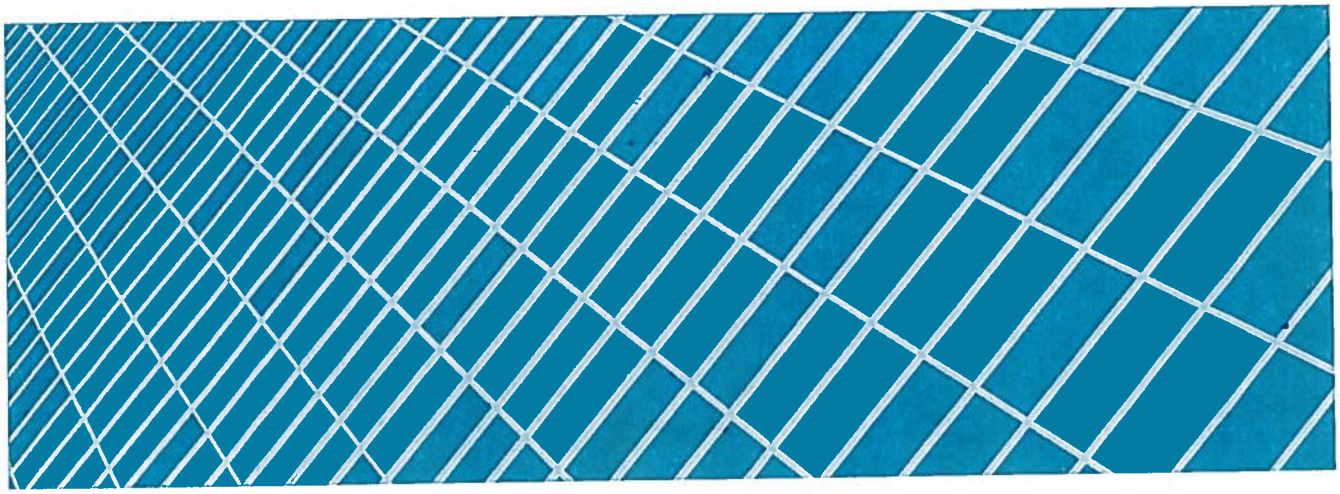


Exhibit 09. Performance Payout Zones

Median responses

	Performance as % of Target			Payout as % of Target		
Measure	**Threshold**	**Target**	**Maximum**	**Threshold**	**Target**	**Maximum**
Sales/revenue	80%	100%	120%	50%	100%	200%
EPS	80%	100%	120%	50%	100%	200%
Cash flow	80%	100%	130%	50%	100%	200%
Operating income/operating profit	80%	100%	120%	35%	100%	200%
EBIT or EBITDA	80%	100%	120%	50%	100%	150%
Net income/earnings/profit	80%	100%	120%	50%	100%	200%



Performance Expectations

"In 2010, the most common approach to establish a performance standard is expected business conditions."

Companies must manage performance expectations by establishing standards to identify what constitutes target performance and to assess the extent to which the target has been achieved. In prior years, budgeted performance was the most widely used approach. In 2010, however, the most common approach to establish a performance standard was based on expected business conditions. As many companies use more than one method to set performance expectations, other common approaches include budgeted performance, year-over-year growth or improvement, investor expectations and performance relative to a peer group.

The approach used to establish performance standards usually varies, based on the performance measure. *Exhibit 10* shows the frequency with which various performance measures are used to set standards. As might be expected, the standards for financial measures are more likely to be based on budgeted performance or year-to-year growth than nonfinancial measures (e.g., customer satisfaction and employee satisfaction), which are often determined by a peer group comparison, or set by management or the board.

Exhibit 10. Factors That Determine Performance Expectations — by Performance Measure

	2010 Survey	2005 Survey
Determined by management/board based on business conditions	58%	25%
Based on budgeted performance	49%	37%
Year-to-year growth or improvement	30%	27%
Peer group performance or some other external standard	15%	1%
Achievement of strategic milestones	11%	1%
Based on expectations of investors	10%	3%
Timeless/absolute standard	5%	1%
Company's cost of capital	4%	—

Payout Levels

We asked survey participants to report the level of bonus payouts made over the past five years, generally covering the period between 2004 and 2008. The pattern of payout levels follows the general economic environment *(Exhibit 11)*. The prevalence of payments in the target-to-maximum range was consistent during the 2004-2007 time frame. In 2008, there was a sizable increase in the prevalence of payments between minimum and target.

Overriding Plan Design

To address unforeseen shifts in the business climate, many companies maintain a degree of flexibility in the administration of annual incentive awards. Companies also want the flexibility to retain key people and keep high performers motivated in difficult times. Generally, for those positions not subject to IRC Section 162(m), companies have the right to adjust individual awards under the established plan formula — either paying an extra reward as a portion of a bonus not warranted by the level of performance or declining to pay a portion of the bonus that was earned based on the level of achievement.

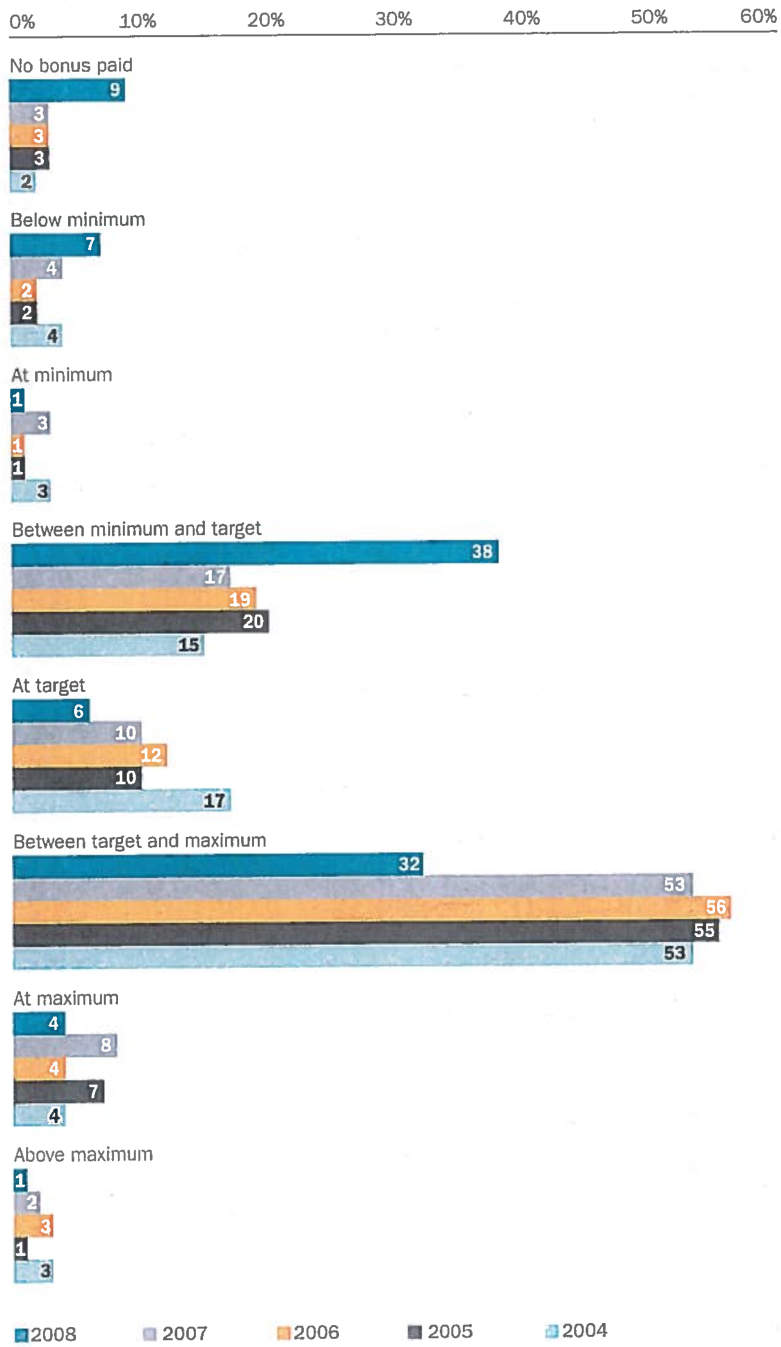
In this survey, we wanted to examine companies' experience with paying awards when performance thresholds were not reached. We learned that about 40% of survey participants had not been faced with such decisions in the previous five years because their organizations had met their thresholds each year.

Another 38% of participants reported they have not overridden the plan when threshold performance was not achieved. This finding suggests that more companies are deciding against overriding plan design. About 20% of survey respondents indicated they have overridden plan formulas and paid a portion of an award either to individuals or groups that did not meet the threshold level of performance. We found that this exception was usually made for a select few individuals rather than for the entire group.

Consistent with our findings in previous surveys, a much smaller percentage of companies (15%) have overridden their plans in the opposite direction, withholding a portion of an award that was earned under their formula. Again, if such an override does occur, it is usually done selectively for some participants.

Exhibit 11. Payout Levels Over Past Five Fiscal Years

% of companies paying out at each level



Award Payment

Size of Awards

The external market exerts considerable influence over incentive practices at individual companies as employers seek to balance their costs with their desire to attract and retain key talent. Of the companies using target bonuses, nearly all (91%) set target opportunities based on external market levels.

External Guidelines

Companies also often look at the bigger picture when trying to calculate the role bonuses will play in an overall compensation package. Again, this helps keep costs in line with objectives while ensuring the organization continues to attract, motivate and retain key talent.

We asked our survey respondents to tell us how competitive they would like to be in both base salary and total cash compensation (base salary plus annual bonus). *Exhibit 12* shows that most companies have targeted pay at the median for base salary and for total cash compensation. However, 26% of companies indicated that they target the 75th percentile for total cash compensation. (Note that target pay is different from actual pay levels.)

Exhibit 12. Desired Competitive Level of Each Compensation Component

	Base Salary	Target Total Cash
Below median	2%	0%
Median	89%	51%
60th percentile	2%	5%
75th percentile	3%	26%
90th percentile	0%	4%
Not specified	2%	12%
Other	2%	1%

Use of Discretion

The use of discretion in awarding incentive payments has become a common practice. Discretion is most likely to come into play with individual performance assessments, but payments can also be adjusted at the discretion of management or the board, or based on business circumstances. A few companies (5%) reported maintaining a special discretionary bonus fund outside the surveyed plans. Thirteen percent of companies reported that awards are not subject to discretion.

Payments in Cash

Most companies reported that their incentive payments are entirely or mostly in cash. About 5% of companies require an alternative, usually some combination of cash and stock. Thirteen percent of companies surveyed have a plan provision that allows bonuses to be paid totally or partially in stock. Among these organizations, it is slightly more common for the company to decide whether the bonus will be paid in stock, in lieu of cash. In some companies, however, participants are allowed to make that decision.

Deferred Payment Arrangements

One-third of the survey group offers plan participants the opportunity to defer payment for individual tax planning or other purposes. However, this practice has decreased significantly since 2001, when over two-thirds of companies reported offering deferral opportunities. This is most likely due to changes in U.S. tax rules, which impose additional restrictions on nonqualified deferred compensation.

"Most companies have targeted pay at the median for base salary and for total cash compensation."

Provisions for Employees Who Leave

Most companies have policies in place for employees who leave during the plan year or after the plan year has ended, but before bonus payments have been made.

If an employee leaves *during the plan year* due to disability, death or retirement, most companies pay a prorated portion of the award *(Exhibit 13)*. If, however, the employee is terminated (for cause) or resigns during the plan year, more than nine out of 10 companies will not pay any bonus. If a person is laid off without cause (e.g., due to a downsizing), companies are divided among paying a partial award, no award or making decisions on a case-by-case basis, with the most common choice being no award.

If an employee leaves *after plan year-end* (but before bonus payments are made) due to disability, death or retirement, most companies will pay the full award *(Exhibit 14)*. If the employee is terminated or resigns after plan year-end, companies are more likely to pay than if the termination occurred midyear. If the individual is laid off without cause after the end of the year, companies are again divided among partial award, no award or making decisions on a case-by-case basis, with the most common choice being to pay the full award.

For the most part, these practices are similar to those reported in the 2005 and 2001 surveys.

Exhibit 13. Bonus Treatment for Status Changes Occurring During Plan Year

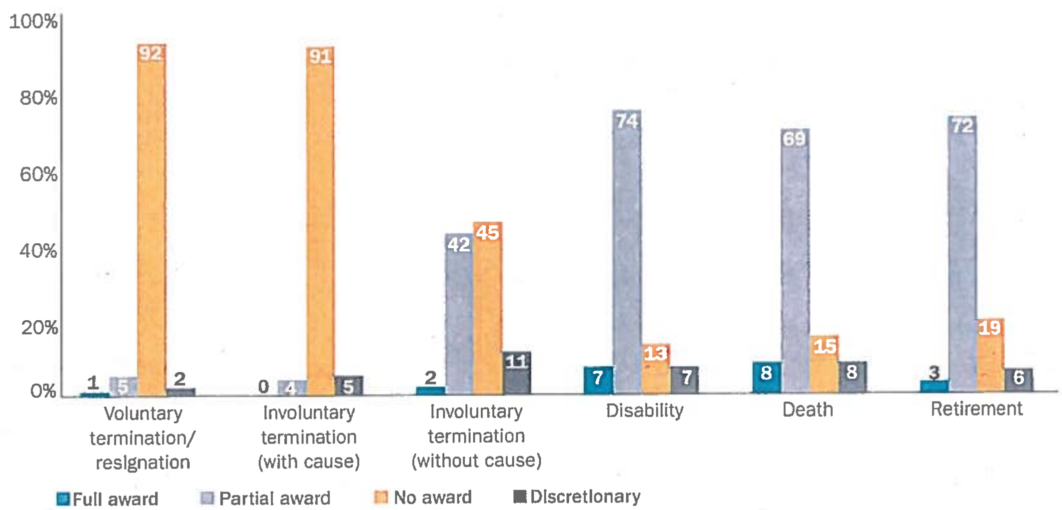
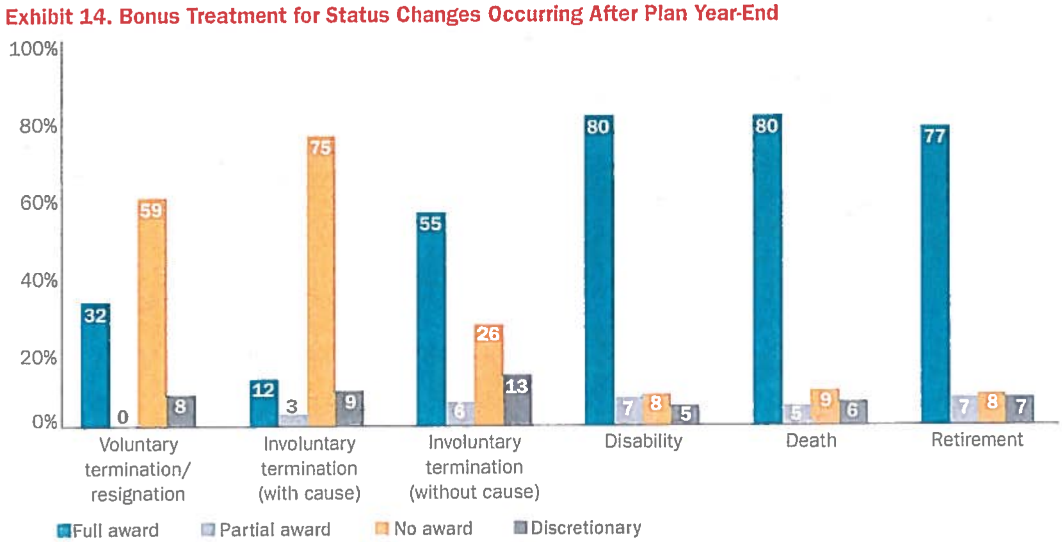


Exhibit 14. Bonus Treatment for Status Changes Occurring After Plan Year-End

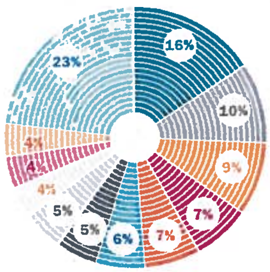


International Issues

About 60% of the companies surveyed include employees outside the home country (either the U.S. or Canada) in their surveyed incentive plan. Almost all of these companies (95%) use a similar plan design to deliver annual incentives to local and third-country national employees on a worldwide basis. Statutory restrictions and market practices are reasons cited by those companies that do not use a similar plan design in other countries.

Appendix

Exhibit A. Participants by Industry



- 16% Energy services
- 10% Insurance
- 9% Food and beverage
- 7% Financial services
- 7% Oil and gas
- 6% High tech
- 5% Chemicals and gases
- 5% Industrial manufacturing
- 4% Pharmaceuticals and biotechnology
- 4% Retail
- 4% Telecommunications
- 23% Other

Exhibit B. Participant List

Number of Participants: 212

Advanced Micro Devices
Agilent Technologies
AGL Resources
Agrium
AIG
Alberta Electric System Operator
Alberta Investment Management
Alliant Energy
Allstate
AMC Entertainment
American Airlines
American Commercial Lines
American Crystal Sugar
American Electric Power
American Family Insurance
American United Life
American Water Works
AMETEK
Anheuser-Busch
A.O. Smith
A&P
ARC Resources
A.T. Cross
Atomic Energy of Canada
AT&T
Automatic Data Processing
Avaya
Avista

BB&T
BC Transmission
Black Hills Power and Light
Blockbuster
Boeing
BOK Financial
BP
Bremer Financial
Brown-Forman

Campbell Soup
Canadian Broadcasting
Canadian Oil Sands
Canadian Pacific Railway
Capital Power
Carlson Companies
Carpenter Technology
CBS
CDI
Century Aluminum
CF Industries
Chevron
Chicago Mercantile Exchange
Chrysler
Chubb
CIGNA
Clearwire
Cobank
Comerica
ConocoPhillips
Constellation Brands
CPP Investment Board
Crown Castle

Dana
Del Monte Foods
Dick's Sporting Goods
Dominion Resources
Domino's Pizza
Dow Chemical
Dow Corning
DPL
Duke Energy
DuPont
Duquesne Light

Eaton
EMC
Energy Future Holdings
Entergy
EQT
Equity Residential Properties
Expedia
Exterran
ExxonMobil

First American
FirstEnergy
First Solar

Genzyme
GNC
Great Canadian Gaming
Greene Tweed

Hanesbrands
Harris
Hayes Lemmerz
H.B. Fuller
Henry Schein
Herman Miller
Hertz
Hewlett-Packard
Hexion Specialty Chemicals
Hoffmann-La Roche
Horizon Blue Cross Blue Shield of New Jersey
Hormel Foods
Hospira
Houghton Mifflin
Humana

IAMGOLD
IDACORP
IKON Office Solutions
IMS Health
Independent Electricity System Operator
Independent Order of Foresters
Insurance Corporation of British Columbia
International Flavors & Fragrances

J.M. Smucker

Kellogg
Kendle International
Kennametal
Koppers
Kroger

Land O'Lakes
Lenovo
Leprino Foods
Level 3 Communications
Liberty Property Trust
Life Technologies
Loto-Québec

Manulife Financial
Maple Leaf Foods
Marathon Oil
Massachusetts Mutual
McCormick
McDermott
McGraw-Hill
MDS
MDU Resources
Medicines
Methanex
M/I Homes
Milacron
Mine Safety Appliances
Molson Coors Brewing
M&T Bank
MTS Allstream
MTS Systems

National Bank of Canada
NAV Canada
New York Life
Nexen
Nicor
Nordstrom
Northeast Utilities
NRG Energy

Ontario Power Generation
Oshkosh Truck
Owens-Illinois

Pacific Gas & Electric
Pacific Life
Papa John's
Pennsylvania Real Estate Investment Trust
People's Bank
Petro-Canada
Plexus
PolyOne
Portland General Electric
Principal Financial
Prudential Financial

QUALCOMM

RGA Reinsurance Group of America
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Schreiber Foods
Schwan's
S.C. Johnson
Securian Financial Group
Security Benefit Group
Shaw Group
Spirit AeroSystems
SPX
SRA International
Starbucks
Starwood Hotels & Resorts
Sunoco
Syncrude Canada

Takeda Pharmaceutical
Tarion
Teradata
Time Warner Cable
T-Mobile USA
Toro
Toronto Hydro Electric Systems
TransCanada
Trinity Industries
Tupperware

UniSource Energy
United States Steel
United Technologies
Unum Group

Valero Energy
Valmont
Vectren
Vermilion Energy Trust
Viacom
Viad
Vulcan Materials
VWR International

Warner Chilcott
Waste Management
Wells' Dairy
Western Digital
Western Union
Whirlpool
Williams Companies
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Xcel Energy

Zale

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Annual Incentive Compensation

2012 Company-Wide Performance Measures For Annual Incentive Compensation Plans

Exhibit ARC-6
Page 1 of 5

Proposed 2012 EPS Performance Measure

- **The EPS performance measure funds the Executive Council Scorecard and Company-Wide Annual Incentive Compensation Program**
  - **Maximum Score:** EPS at or above $3.28 results in a 200% of target award pool
  - **Target Score:** EPS of $3.12 results in a target award pool
  - **Threshold Score:** EPS at $3.00 results in a 25% award payout
    - The payout for threshold performance in previous years was 0%

	EPS Requirement	Award Score
Maximum Award	≥ $3.28	200%
Target	= $3.12	100%
Threshold	= $3.00	25%
Below Threshold	< $3.00	0%

Exhibit ARC-6
Page 2 of 5

Proposed 2012 EPS Performance Measure

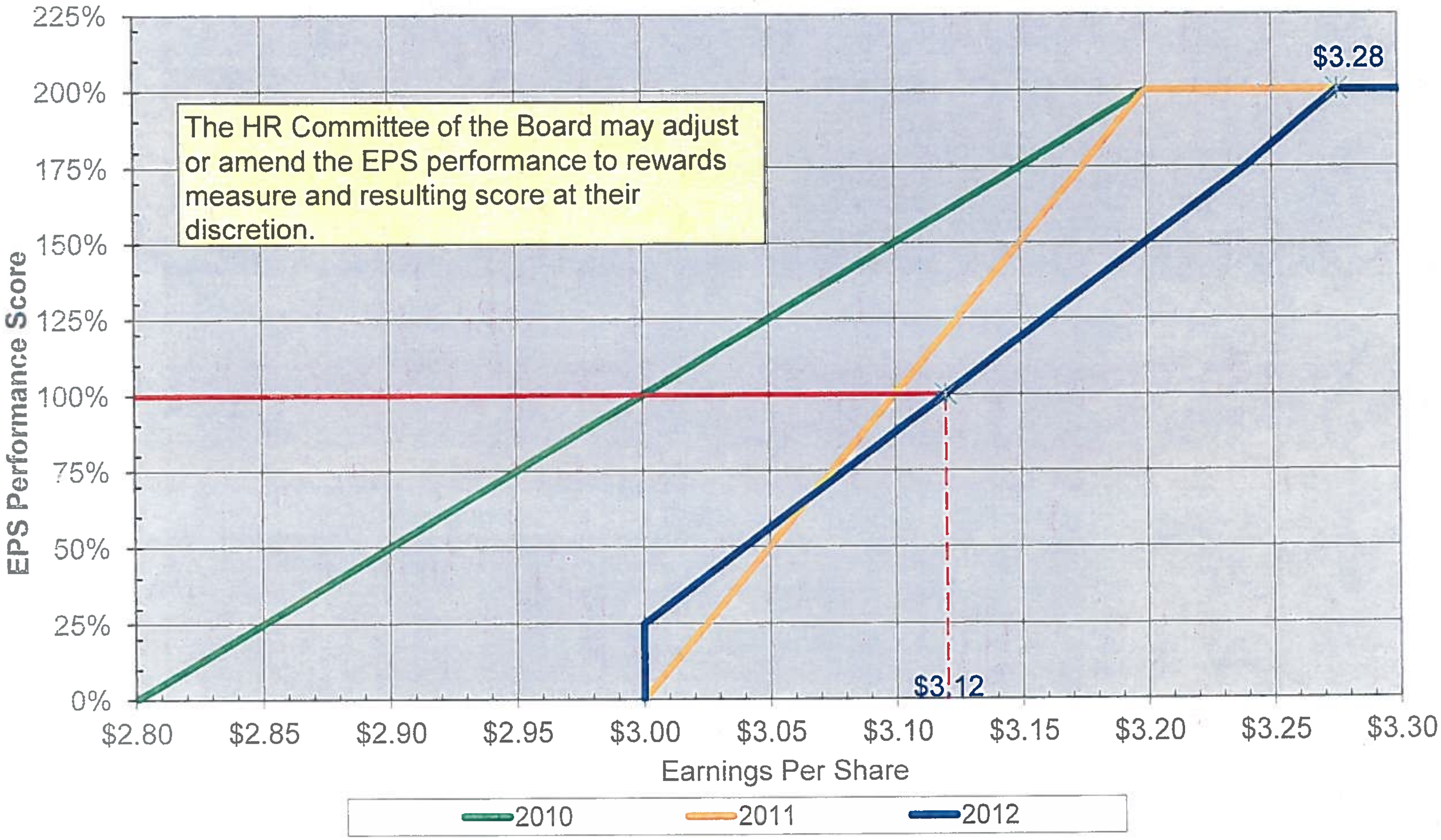


Exhibit ARC-6
Page 3 of 5

2012 Company-Wide Annual Incentive Compensation Fatality Adjustment

- **Fatality Adjustment:**
  - In the event AEP does not experience a fatal work related employee accident, the company would celebrate this accomplishment by increasing the overall net composite score by:
    - 10% of the actual score for all officers, and
    - 5% of the actual score for all other employees
  - In the event AEP does experience a fatal work related employee accident, the overall net composite score would be reduced by:
    - 10% of the actual score for all officers,
    - 10% of the actual score for all employees in the group that experienced the fatality, and
    - 5% of the actual score for all other employees
  - This would add or deduct funding outside of the EPS funding mechanism
  - This changes the Fatality Adjustment calculation to a percentage of the actual score, from a percentage of target

Exhibit ARC-6
Page 4 of 5

2012 Company-Wide Annual Incentive Compensation
EPS Modifier

Objective: Normalize relative incentive group scores to the EPS score to:

- Ensures that payouts are always commensurate with AEP's EPS performance and
- Differentiate award funding based on each incentive group's relative performance

- The EPS Modifier is a fair method of allocating the incentive funding accrued based on the earnings produced for shareholders
- The EPS Modifier ensures that the sum of the award pools for all groups equals the overall actual company-wide award pool, plus or minus the Fatality Adjustment

$$\frac{\text{EPS Performance Score}}{\text{Wt. Avg. Group Score}} = \text{EPS Modifier}$$

$$\left(\text{Group Score} \times \text{EPS Modifier}\right) \pm \text{Fatality Adjustment} = \text{Award Factor}$$

- The target award pool for AEP as a whole is equal to the sum of the target awards for all participants
- The actual award pool for AEP as a whole is the target award pool multiplied by the EPS score plus or minus the Fatality Adjustment

Exhibit ARC-6
Page 5 of 5

Annual Incentive Compensation

2012 Executive Council Scorecard

Exhibit ARC-7
Page 1 of 16

2012 Senior Officer Scorecard
Performance Measures and Weights Summary

- **Balanced scorecard of strategic and operational measures**
  - **Focused on measurable, quantifiable goals but includes subjective assessments of success in less quantifiable areas**

Performance Category	2012	2011	2010	2009
Funding	**EPS**	EPS	EPS	EPS
Funding Adjustments	**Fatality Adj. (+/- 10%)**	Fatality Adj. (+/- 10%)	Fatality Deduction	Fatality & Credit Rating Deductions
Safety & Health	**25%**	30%	25%	24%
Operations	**25%**	30%	25%	21%
Total Current Operations	**50%**	60%	50%	45%
Regulatory	**-**	20%	25%	30%
Strategic Initiatives	**50%**	20%	25%	25%
Total Business Development	**50%**	40%	50%	55%

Exhibit ARC-7
Page 2 of 16

Category: Safety & Health Severity Rate (12%)

- First year of a new five-year glidepath leading to achievement of top decile severity rate performance among EEI comparable companies
  - Maximum 200% payout for achieving glidepath to top decile performance
  - Target 100% payout for performance 15% higher (worse) than top decile

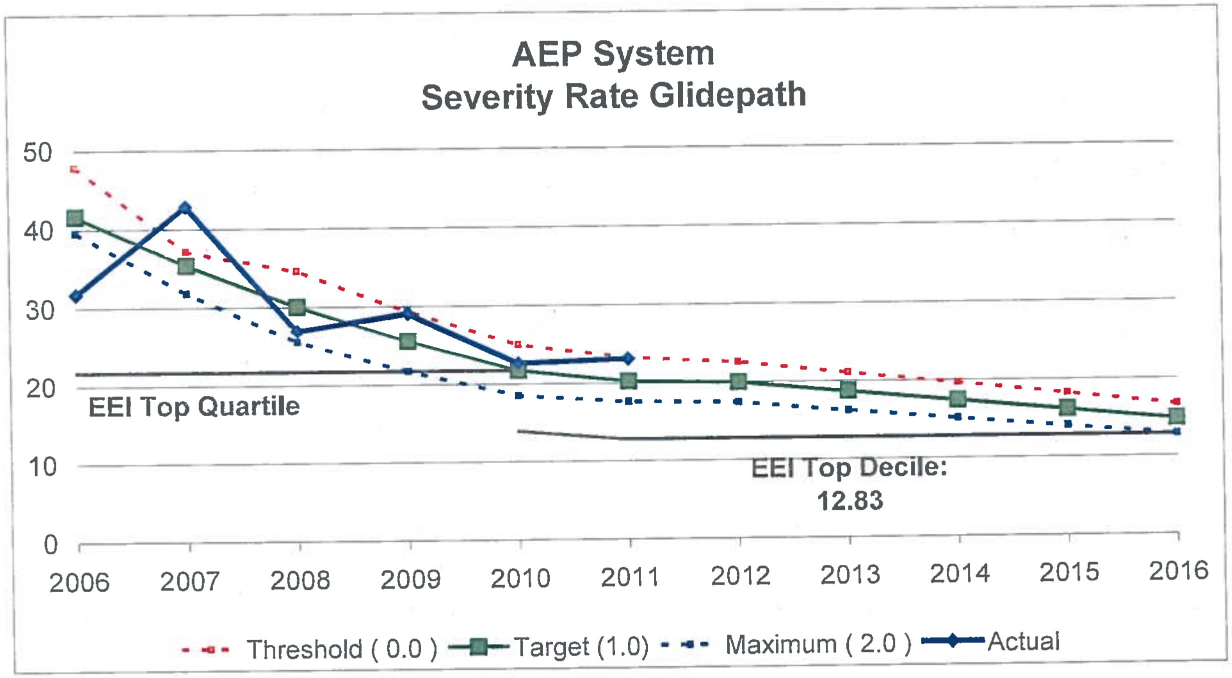


Exhibit ARC-7
Page 3 of 16

Category: Safety & Health
Recordable Incident Rate (8%)

- First year of a new five-year glidepath leading to achievement of top decile recordable incident rate performance among EEI comparable companies
  - Maximum 200% payout for achieving glidepath to top decile performance
  - Target 100% payout for performance 15% higher (worse) than top decile

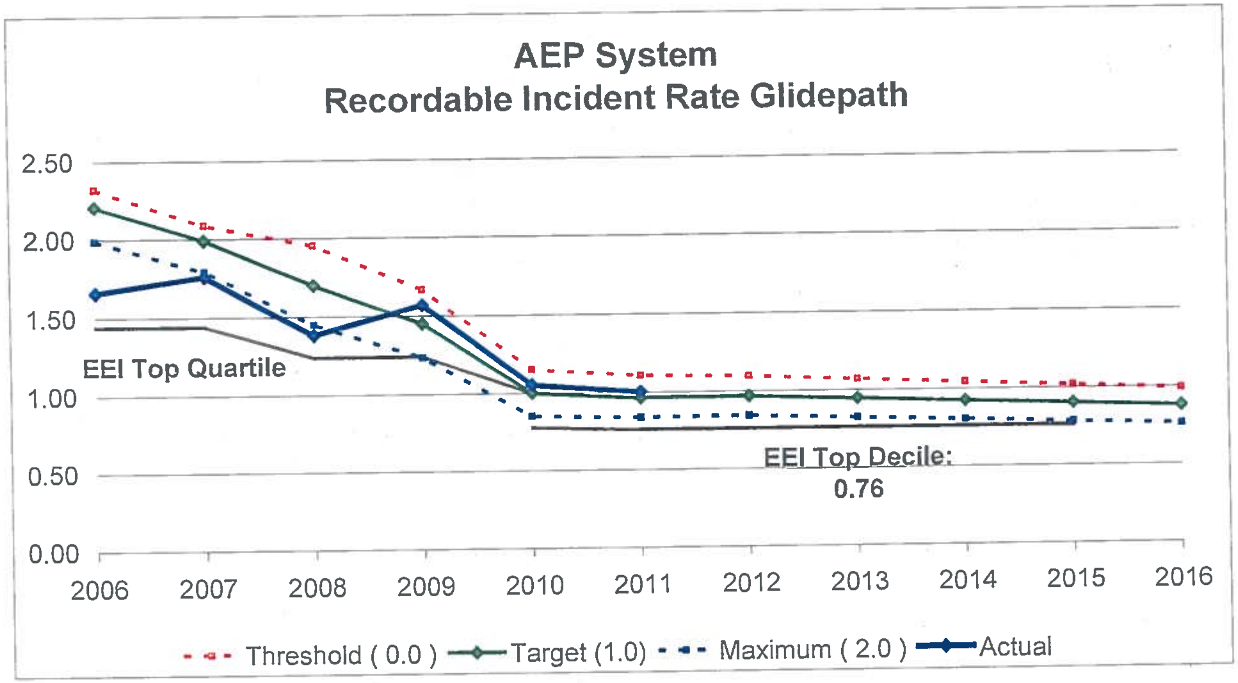


Exhibit ARC-7
Page 4 of 16

AEP®

Category: Safety & Health
Contractor Recordable Incident Rate (5%)

- **Year two of a five-year contractor recordable incident rate glidepath**
  - **This measure will be expanded over time to include more AEP contractors as additional contractors safety information becomes available. The glidepath may be adjusted, if needed, to reflect these additions**

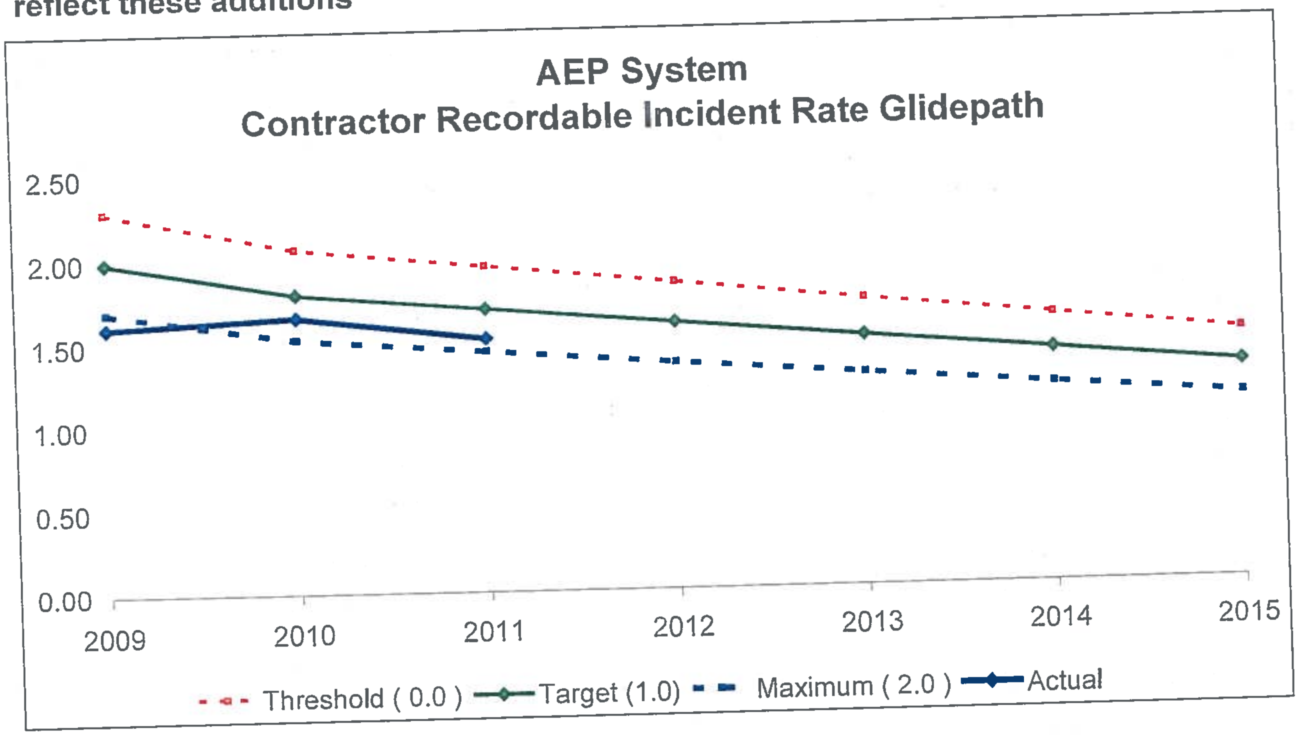


Exhibit ARC-7
Page 5 of 16

Category: Safety & Health
2012 Safety Goal Table (25% of Total)

		Performance Measures*					
		Severity Rate (12% of Plan)		Recordable Case Rate (8% of Plan)		Contractor Recordable Case Rate (5% of Plan)	
	Award	Rate	% of Top Decile	Rate	% of Top Decile	Rate	% of Target
Threshold	0%	22.54	130%	1.09	130%	1.84	115%
Target	100%	19.94	115%	0.97	115%	1.60	100%
Maximum	200%	17.34	100%	0.84	100%	1.36	85%

* Safety and severity objectives exclude River Transportation for comparability to EEI statistics.

- **Severity rate:**
  - **Excludes fatalities in accordance with OSHA methodology**
  - **Includes restricted duty days in both AEP results and EEI percentile targets**

Exhibit ARC-7
Page 6 of 16

Category: Operations
NERC Reliability Compliance (5%)

- There are two components of the NERC reliability compliance goal that will be measured for AEP Transmission:
  1. The score, up to 100% of target, will be based on the percentage of specific goals that are completed under the following strategic compliance initiatives:
     - Ensure timely and accurate completion of all NERC Compliance Monitoring and Enforcement Program deliverables and Mitigation Milestones
     - Improve Reliability Compliance
     - Improve Reliability Compliance monitoring and enforcement
     - Analyze AEP compliance practices, and identify other compliance improvement opportunities
     - Improve awareness of compliance across Transmission
  2. If all of the above strategic compliance initiatives are completed, then the score will be at target or above based on the percentage of potential compliance issues (PCIs) that are identified internally as follows:
     - Target (100%) score if <85% of PCI's are identified internally
     - 125% of target if 85% of PCI's identified internally
     - Maximum (200%) score is 100% of PCI's are identified internally

Exhibit ARC-7
Page 7 of 16

Category: Operations
EFOR (Equivalent Forced Outage Rate) – Peak Months (3%)

- Equivalent Forced Outage Rate (EFOR) reflects the equivalent percent of scheduled operating time that a unit is out of service due to unexpected problems or failures
  - The peak months are January, February, June, July and August
  - Certain outage events that are out of management's control are excluded
  - The metric includes all hydro units and specific coal & gas units
  - Unit targets are based on the approved 4Q 2011 generation plan plus 0.20% for the included coal, gas, and Smith Mountain units
    - The additional 0.20% is intended to cover a major failure (e.g. Cardinal 2 in 2011), the upward trend in EFOR, reduced maintenance budget availability, and the unknown impact of operating the units differently in 2012
    - These targets will be used to calculate the selected coal, gas and hydro fleet monthly EFOR targets using actual service and forced outage hours
  - The EFOR – Peak Months score will be determined as follows:
    - Threshold (0% score) EFOR = 10.03 (+1.5%)
    - Target (100% score) EFOR = 9.88%
    - Maximum (200% score) EFOR = 9.78% (-1.0%)
      - As was the case in prior years, the threshold to target and target to maximum bandwidths are not equal because the probability of worse than target EFOR performance is larger than the probability of better than target EFOR performance
      - Major equipment failures could substantially impact EFOR while any improvements that can be made relative to the target are likely to have a relatively small effect

Category: Operations
EFOR – Off-Peak Months (2%)

- The off-peak months are March, April, May, September, October, November and December
- The calculation methodology is the same as for the EFOR - Peak Months calculation but the weight is lower because the market value of off-peak generation is lower

AEP®

Category: Operations
Reliability - System Avg. Incident Duration Index – (5%)

- Reliability is measured by SAIDI (System Avg. Incident Duration Index) as the system average customer minutes of interruption
  - SAIDI improves with outage prevention and/or a reduction in the number of customers effected by each incident
  - SAIDI also improves when the time needed to restore power is reduced
  - SAIDI is a primary measure chosen by regulators and peers
  - SAIDI measures reliability from the viewpoint of the "average" customer
- SAIDI targets for each operating company are based on mandated jurisdictional targets, if they exist, or a 10 year reliability glidepath to achieve the lower (better) of:
    - The SAIDI performance of regional peers, or
    - The operating company's three-year average actual performance
  - Operating company targets are held flat if cost recovery for reliability improvements is denied
  - Targets and actual results exclude major event days
  - The target increased for 2012 due to a PUC mandated SAIDI target negotiated with the Ohio PUC
- The SAIDI score for the E.C. Scorecard is the average of the operating company SAIDI scores weighted by the sum of the incentive targets for each operating company

Exhibit ARC-7
Page 10 of 16

Category: Operations
Reliability – SAIDI (continued)

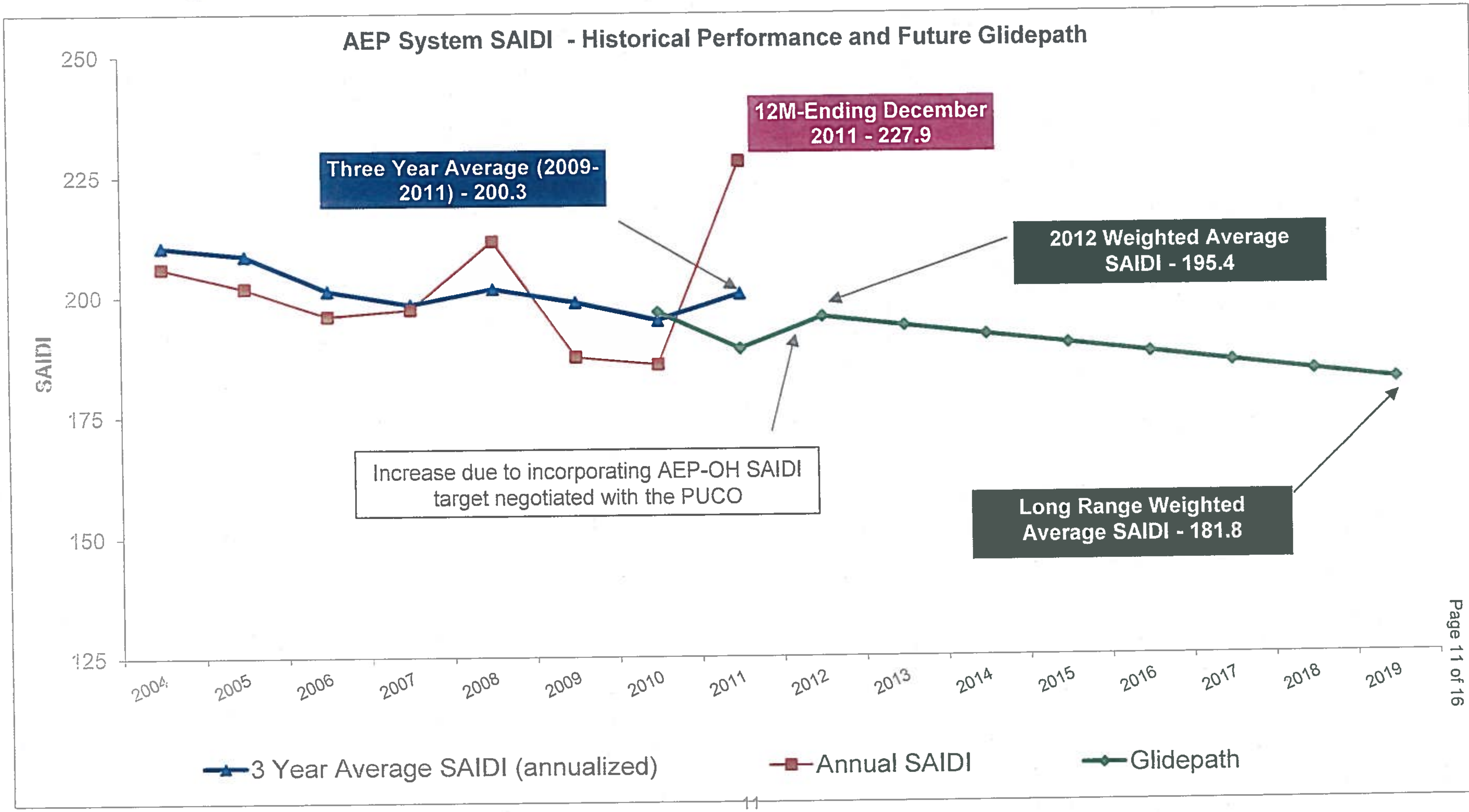


Exhibit-ARC-7
Page 11 of 16

Category: Operations
NRC Cornerstone Indicators (5%)

- The Seven Cornerstones of Safety are:
  - Initiating Events
  - Mitigating Systems
  - Barrier Integrity – Reactor Safety
  - Emergency Preparedness – Reactor Safety
  - Occupational Radiation Safety – Radiation Safety
  - Public Radiation Safety – Radiation Safety
  - Physical Protection – Safeguards
- Performance Indicators (PIs) are evaluated quarterly for each cornerstone of safety and given a color designation based on their safety significance
  - Green cornerstone indicator PIs correspond to very low risk significance and therefore have little or no impact on safety
  - White, yellow, or red PIs each, respectively, represent a greater degree of safety significance
- The NRC Cornerstone Indicator score will be determined as follows:
  - Threshold (0% score) = 2 White
  - Target (100% score) = All Green
  - Maximum (200% score) = Sustain All Green

Category: Operations
INPO Index (5%)

- The Institute of Nuclear Power Operations (INPO) index is a composite of the following plant operations measures calculated as prescribed by INPO:
  - Unit Capability Factor
  - Forced Loss Rate
  - Unplanned Auto Scrams
  - Safety System Performance
  - Fuel Reliability
  - Chemistry Performance
  - Collective Radiation Exposure
  - Industrial Safety Accident Rate

- The INPO Index score will be determined as follows:
  - Threshold (0% score) INPO Index = 85
  - Target (100% score) INPO Index = 90
  - Maximum (200% score) INPO Index = 95

Category: Strategic Initiatives
Corporate Separation, East Pool Reform and Development of a Competitive Unregulated Business (20%)

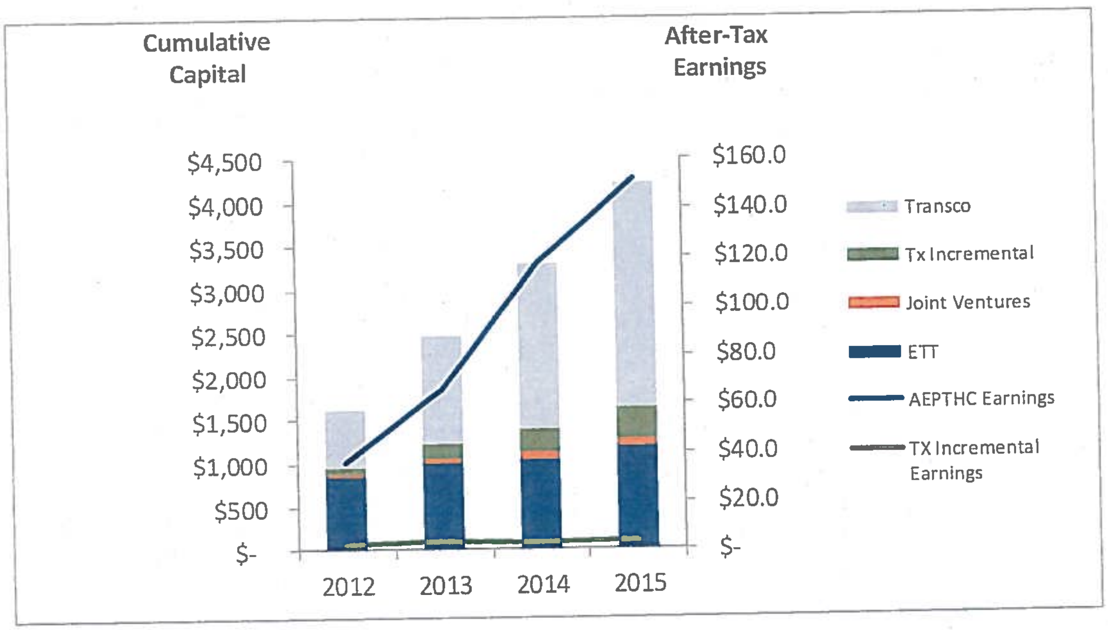
- Assumption: Timely PUCO order approves the ESP and corporate separation applications in their current form or modifies them in a manner that is acceptable to AEP Ohio
- Corporate Separation
  - File FERC 203 and 205 cases and make progress towards successful corporate separation
  - Make certain other necessary regulatory notifications and filings for asset transfers, contracts/agreements (including but not limited to transfers or amendments), etc., and make progress towards successful completion of these transactions
- Interconnection Agreement
  - State commission outreach to facilitate acceptable, timely termination of AEP Interconnection Agreement (East Pool) and potential replacement with a new three-company arrangement
- Competitive Business
  - Make progress towards development and creation of a competitive unregulated energy business, inclusive of capitalization and financing for Ohio generating assets and competitive retail
  - Successfully complete BlueStar Energy acquisition and integration
- Specific objectives and performance measure details will be provided along with performance updates and supporting information throughout the year
- This measure will be subjectively scored by the HR Committee
- The effect of regulatory procedural schedule changes and/or material uncontrollable events shall be removed to avoid score impact

Exhibit ARC-7
Page 14 of 16

Category: Strategic Initiatives
Transmission Earnings Growth (15%)

Achieve/Exceed 2012 Transmission Transco and JV Earnings Target ($37.9 million)

- 90% of Earnings Target = 0% of target score
- 100% of Earnings Target = 100% of target score
- 110% of Earnings Target = 200% of target score



Category: Strategic Initiatives
Turk Completion (15%)

- Achievement of major 2012 objectives for the Turk Plant, including timely and successful:
  - Permitting
  - Public outreach
  - Communications
  - Rate case filings and support
  - Commercial operation in Q4 2012
- The effect of approved schedule changes and major uncontrollable events shall be removed so as not to impact the score either positively or negatively
- This is a subjective measure to be scored by the HR Committee of the Board

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September 2003

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Abstract

While the business press suggests that "winning the talent war," the attraction and retention of key talent, is increasingly pivotal to organization success, executives often report that their organizations do not fare well on this dimension. We demonstrate how, through integrating turnover and compensation research, the Boudreau and Berger (1985) staffing utility framework can be used by industrial/organizational (I/O) psychologists and other human resource (HR) professionals to address this issue. Employing a step-by-step process that combines organization-specific information about pay and performance with research on the pay-turnover linkage, we estimate the effects of incentive pay on employee separation patterns at various performance levels. We then use the utility framework to evaluate the financial consequences of incentive pay as an employee retention vehicle. The demonstration illustrates the limitations of standard accounting and behavioral cost-based approaches and the importance of considering both the costs and benefits associated with pay-for-performance plans. Our results suggest that traditional accounting or behavioral cost-based approaches, used alone, would have supported rejecting a potentially lucrative pay-for-performance investment. Additionally, our approach should enable HR professionals to use research findings and their own data to estimate the retention patterns and subsequent financial consequences of their existing, and potential, company-specific performance-based pay policies.

Is it Worth it to Win the Talent War? Evaluating the Utility of Performance-Based Pay

The ability to achieve competitive advantage through people depends in large part on the composition of the work force. This, in turn, is a function of who is hired, how they are developed, and who is retained—the latter of which is the focus of this study. Voluntary employee turnover can be either dysfunctional or functional for the organization, depending on who leaves (Boudreau, 1991; Boudreau & Berger, 1985; Hollenbeck & Williams, 1986; Trevor, 2001). Both low and high performers are generally more likely to leave an organization than are average performers (Jackofsky, 1984; Trevor, Gerhart, & Boudreau, 1997; Williams & Livingstone, 1994). Thus, organizations often will shed poor employees (functional turnover), but will also fail to retain star employees (dysfunctional turnover). It appears, however, that organizational practices can influence the performance distribution of leavers. Specifically, though high performers typically may leave the organization more often than do average performers, they do not necessarily do so. While research consistently reports that an organization's pay system affects the probability of voluntary turnover (Dreher, 1982; Gerhart & Milkovich, 1992; Griffeth, Hom, & Gaertner, 2000; Harrison, Virick, & William, 1996; Porter & Lawler, 1968; Schwab, 1991; Steers & Mowday, 1981; Trevor et al., 1997), the probability of high-performer turnover is particularly sensitive to the strength of the pay-for-performance link (Trevor et al., 1997). Consequently, organizations may be able to design compensation systems to enhance organizational value by targeting retention efforts at the dysfunctional high performer turnover.

This may in fact be increasingly happening as organizations in the United States and abroad are progressing toward linking pay more strongly to performance (Milkovich & Newman, 2002). Although many organizations have expanded their use of plans that reward team, business unit, and corporate performance (Milkovich & Newman, 2002), the predominant basis for pay-for-performance continues to be individual performance (IOMA, 2002; Hewitt Associates, 2002), and survey data indicate that companies believe individual pay-for-performance programs are effective (IOMA, 2002). While there are concerns about the wisdom of pay-for-performance (e.g., Kohn, 1993; Pfeffer, 1998), particularly for individual performance, research reviews find ample evidence that pay-for-performance is associated with higher performance at both the individual (Jenkins, Mitra, Gupta, & Shaw, 1998) and organizational levels of analysis (Gerhart, 2000). Such research, however, has not explicitly examined the mechanisms through which pay-for-performance plans affect individual behaviors to influence the organizational bottom line. One such mechanism involves pay-for-performance's effects on performance-specific turnover, and the associated costs and benefits that contribute to organizational financial performance.

The professional HR literature suggests that influencing the retention of high performers in particular is a crucial matter. Many articles cite the increasing difficulty in obtaining and keeping top talent (e.g., Bartlett & Ghoshal, 2002; Branch, 1998; Chambers, 1998; Rich, 1999). A report based on interviews of over 5,000 executives and managers (McKinsey & Company, 1998), for example, found that 65% of executives believed that they had insufficient talent in the ranks of their top 300 leaders and only 10% strongly believed that their companies retained most of their high performers. Even with the recent economic slowdown, organizations face increased pressures to attract and retain top talent in their most pivotal talent areas. The Bureau of Labor Statistics projects that, by 2010, the labor supply will grow by 17 million (Fullerton & Toosi, 2001) while labor demand will increase by 22.2 million (Berman, 2001), indicating that labor shortages will play increasing roles in the future. Moreover, even if a company is reducing employee headcount, voluntary attrition is often the first and most attractive option (Sherwyn & Sturman, 2002). Each of these circumstances highlights the potential benefits of managerial investments that particularly facilitate top-performer retention.

Few would debate the merits of a performance-based pay practice that, all else equal, resulted in greater retention of high performers. Unfortunately, all else is far from equal when changing an organization's pay systems. Because such changes will affect total labor costs, individual employee pay levels, and subsequent employee behaviors, the critical question becomes one of whether the benefits of such a practice outweigh the costs. We propose that while the potential retention benefits of incentive pay have been recognized, they have yet to be quantified in dollar terms. Moreover, researchers have failed to adequately address actual costs of performance-based bay. Our goal here is to provide the first empirical cost-benefit assessment of the viability of performance-based pay. Our approach should contribute to the pay-for-performance literature by specifying the circumstances that affect the success of pay-for-performance plans.

Our results should also contribute to practice, as the likelihood that HR professionals would apply the research findings to their own organizations should increase if these professionals are provided with a viable technique for doing so. In this paper we demonstrate such a technique. The employee movement utility model of Boudreau and Berger (1985) provides the means to evaluate the dollar value implications of various pay-for-performance strategies, which we illustrate with a step-by-step application to a published turnover and pay-for-performance article. In doing so, we (a) demonstrate how organizational representatives can use research findings, publicly available compensation and turnover data, or their own data to diagnose, inform, and evaluate their own company-specific incentive pay decisions; and (b), demonstrate that this technique will often provide different conclusions from typical decision models that use only traditional cost or accounting analysis.

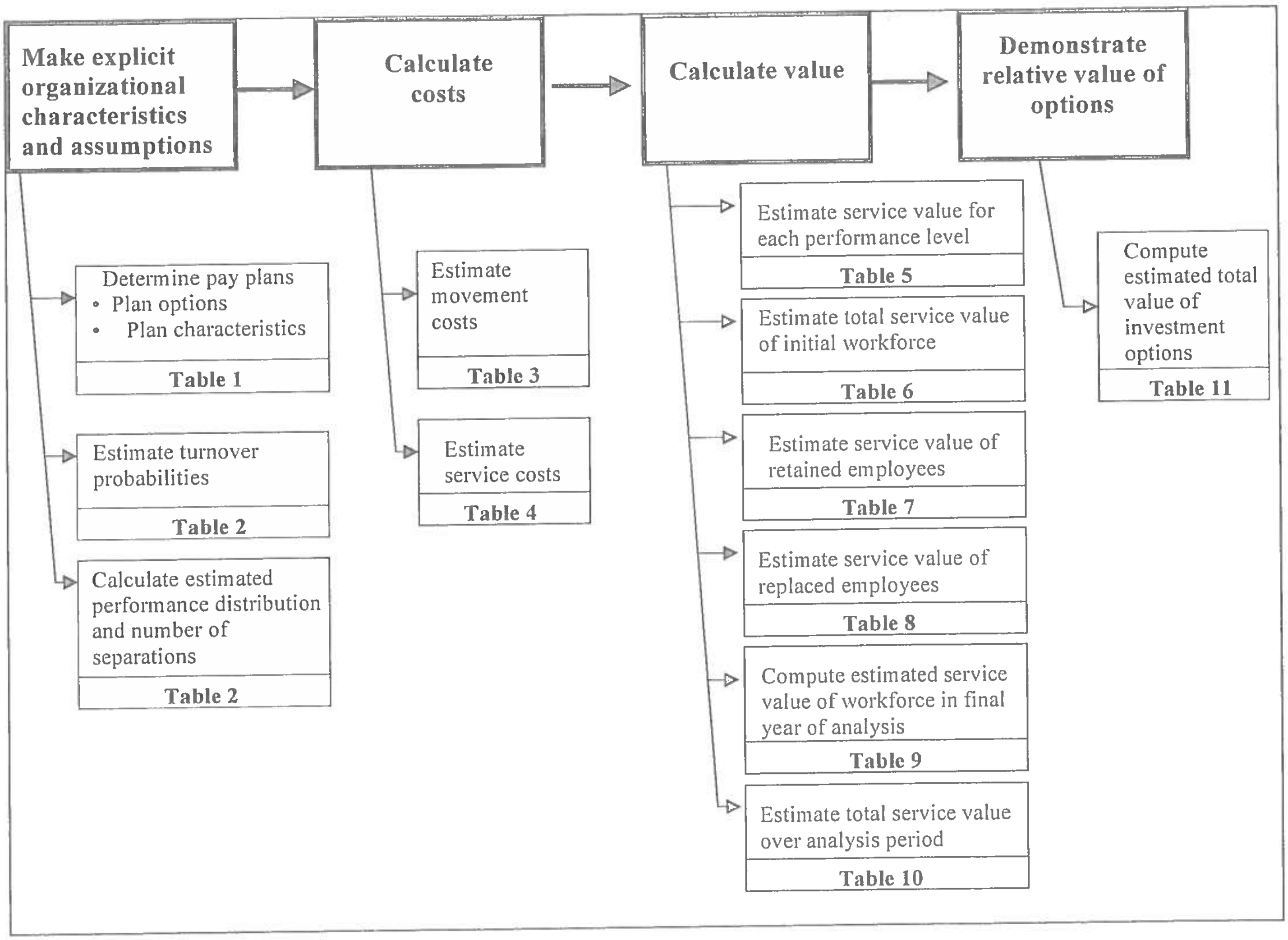
Utility Analysis Applied to Pay Decisions

Utility analysis is a tool for cost-benefit analysis that helps quantify the impact of human resource interventions (Cascio, 2000). While utility analysis has been applied to numerous human resource program areas, most applications have concentrated in the areas of employee selection and training (Boudreau & Ramstad, 2003b; 1999; Boudreau, 1991). The Boudreau and Berger (1985) framework represents one of the few applications to employee retention. Klass and McClendon (1996) used that framework to examine the pay policy decision of whether to lead, lag or match the market. They gathered parameter information from published studies and simulated effects on employee separation and offer acceptance patterns. Results for bank tellers suggested that a lag policy produced higher payoffs, although "leading the market" (paying higher than the average) did enhance retention and attraction of top candidates. The authors noted that these results did not necessarily suggest using a particular pay policy, and showed how simulated reductions in citizenship behavior due to low pay might change the results. This was an important initial application of employee movement utility principles to decisions about pay.

In this paper, we focus on a different type of pay decision – how to allocate pay increases across employees at different performance levels. Trevor et al. (1997) found that pay policies providing greater pay growth for high performers (and less for low performers) substantially increased retention among high performers, encouraged separation among low performers, and thus increased the value of the work force. This is an appealing prospect, but it is unclear whether the enhanced workforce value would offset the cost associated with such a reward system. Such costs are quite apparent using traditional accounting or behavioral costing models, but such models have limited ability to reflect effects on workforce value; furthermore, little data exists on the actual implications of these limitations (Boudreau & Ramstad, 2003a; 2003b). It is also unclear to what extent the enhanced workforce value would depend on such factors as the pay policy specifics, the retention pattern, and the variability in performance. The Boudreau-Berger utility framework provides a method to address these questions.

Using the Boudreau and Berger (1985) separation/acquisition utility model, our paper presents a model that captures the value associated with employee separations (turnover) and acquisitions (hires) over time. The model estimates three components in each time period: (a) movement costs—the costs associated with employee separations and acquisitions; (b) service costs—the pay, benefits, and associated expenses required to support the work force; and (c) service value—the value of the goods and services produced by the work force. The dollar-valued implications of a given pay plan, and of the subsequent separation and acquisition patterns over time, are estimated by subtracting the movement costs and service costs from the service value (i.e., subtracting the pay plan's costs from its benefits). Figure 1 shows the steps necessary to compute this estimate and the tables we employ here to illustrate these steps.

Figure 1
Flow Chart of Utility Analysis Procedure



The Illustrative Case Study

We illustrate our approach using a scenario in which a hypothetical company is considering implementing a pay-for-performance plan at the end of the year 2003. We assume that the company does not currently relate pay to performance, so under the current strategy all employees would receive the same pay increases over time. We compare the effects of this strategy with those of two alternative strategies that place different emphases on pay-for-performance. We choose to evaluate the implications of the three possible approaches over a four-year period (2004 to 2007). Thus, because pay-for-performance affects turnover differently at different levels of performance (Trevor et al., 1997), the 2007 workforce would reflect a different performance distribution under each of the three pay strategies. By calculating the movement costs, service costs, and service values from 2004 to 2007, we can estimate the cumulative effects of the pay strategies over the four-year period.[1]

We used a number of spreadsheets to make the necessary calculations, with each spreadsheet corresponding to a table in this paper. The spreadsheets are available from the lead author upon request, although the descriptions we provide here should be sufficient for many readers to create their own. We also make a number of assumptions to perform the necessary calculations. These assumptions are all based on published research (e.g., Trevor et al., 1997) or publicly available data (e.g., BLS, 2002). First, we draw directly from the Trevor et al. (1997) study to estimate (a) the relationship between pay growth, performance, and turnover that is captured in their survival analysis (see Appendix) and is used to calculate the turnover probabilities at each performance level under each pay strategy; (b) the baseline turnover probability necessary to compute those turnover probabilities that are specific to each performance level-pay strategy combination; and (c) the performance distribution at the beginning of our utility analysis timeframe.

It should be noted that the Trevor et al. (1997) data are from all 5,143 exempt employees hired by a large petrochemical organization between 1983 and 1988. Furthermore, Trevor et al. (1997) examined the effects of various strengths of pay-for-performance relationships based on archival data on individuals' performance and pay levels; they did not specifically manipulate the pay-for-performance link as part of either an experimental or quasi-experimental design. Nonetheless, these data represent a wide variety of exempt jobs over several years, and the results provide valuable insight into the relationships between turnover, pay, and performance. Thus, the results of the Trevor et al. (1997) study are useful for our purpose of illustrating our technique.

Second, we use published surveys (WorldatWork, 2002; BLS, 2002) to help generate realistic pay strategies, determine starting average pay levels, and estimate benefit costs. Finally, we employ the results of published research studies to help provide realistic estimates of the cost of turnover (e.g., Solomon, 1988; Johnson, 1995) and the value of different levels of employee performance (Becker and Huselid, 1992; Boudreau, 1991; Cascio, 2000; Schmidt and Hunter, 1983). We describe the rationale for our assumptions and suggest how professionals might apply each rationale or gather their own data to customize the application for their organizations. Thus, our demonstration is intended (a) to provide information on the value of pay-for-performance plans and the extent that they should ultimately lead to improved organizational financial success; and (b) to enable others to use the method with their own company's data, new research findings, and/or their own estimates to create company-specific evaluations to facilitate their own decision-making regarding the implementation of pay-for-performance policies.

Pay-For-Performance Plans and Performance-Specific Turnover

Step 1: Specify the Pay-for-Performance Options

As is evident in Figure 1, the first major phase in estimating the costs and benefits of performance-based pay is to make explicit the relevant organizational characteristics and assumptions. The initial step within this phase is to specify the pay policy scenarios to be considered. The two key parameters needed are: (a) the current pay level in each performance category for the employees to be considered; and (b) the relationship between pay growth and performance levels (usually expressed in terms of the percentage increase awarded for each performance level). For this second parameter, we constructed three hypothetical, but realistic, performance-based pay strategies. Because we intend to provide a broad range of potential outcomes, within which most particular organizational results should fall, the strategies were chosen to range from conservative to aggressive in terms of the pay-for-performance link. In terms of performance categories, we adopted the nine performance-rating categories used by Trevor et al. (1997), which range from 1.0 (lowest performance) to 5.0 (highest performance) in 0.5 increments, because this will facilitate using other aspects of the Trevor et al. situation as an illustration. Trevor et al. (1997) created the nine categories by computing average performance over time from a rating system in which "The performance scale ranged from 1 = lowest to 5 = highest, with the five categories representing levels of consistency in meeting and exceeding the basic requirements of the job" (p. 49). Professionals adopting our utility analysis framework should change the performance categories to reflect their own performance assessment approach.

Table 1
Pay Strategies and Estimated Four-Year Pay Levels for Each Strategy

Performance Ratings:	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Pay Increase for Pay Strategy 1	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**
Pay Increase for Pay Strategy 2	**4%**	**4%**	**4%**	**4%**	**4%**	**5%**	**6%**	**7%**	**8%**
Pay Increase for Pay Strategy 3	**0%**	**1%**	**2%**	**3%**	**4%**	**5%**	**6%**	**7%**	**8%**
2003 Average Pay	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**
Pay Strategy 1: No pay/performance link									
2007 Average Pay	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133
Pay Strategy 2: Pay for performance e link for above average performer									
2007 Average Pay	$56,133	$56,133	$56,133	$56,133	$56,133	$58,324	$60,577	$62,896	$65,280
Pay Strategy 3: Pay for performance link for all performers									
2007 Average Pay	$47,983	$49,931	$51,938	$54,005	$56,133	$58,324	$60,577	$62,896	$65,280

Note: Data provided by the user **are in bold.**

The details of our three illustrative pay-for-performance plans are shown in Table 1. Pay strategy 1 gives all employees the same average pay increase, regardless of performance level. Data suggest that current pay increases average 4% (WorldatWork, 2002; BLS, 2002; Peck, 2002), so we used this value for all performance categories in pay strategy 1. Pay strategy 2 creates a pay-performance link (i.e., larger pay increases as performance improves) for performers above the middle "3.0" rating, and average pay increases (i.e., 4%) to those rated

3.0 and below. Pay strategy 3 maintains the positive reinforcement of pay strategy 2, and extends the pay-for-performance link to those below the middle rating (i.e., smaller pay increases as performance worsens). Thus, pay strategy 1 provides no performance link, pay strategy 2 is more aggressive, and pay strategy 3 is the most aggressive.

As noted above, in addition to the pay raise strategy, step one requires the setting of an initial pay level upon which the pay strategies will be applied. Because our example involves evaluating the pay-for-performance strategies for white-collar employees, we used the Bureau of Labor Statistics (BLS, 2002) estimate of average 2001 white collar (non-sales) pay, adjusted for the average salary increases of exempt workers for 2002 and 2003 (WorldatWork, 2002). This ultimately yielded a pay level of $47,983 for the year 2003.[2] For illustration, we simply assigned this same initial pay level to every performance category. Then, applying the percentage increase associated with each pay strategy and extrapolating for four future years, we projected the resulting performance-specific pay levels for the year 2007, as reported in Table 1.

In actual organizations, of course, the current pay levels would be available from company records. The same forward-projection method can be used based on these initial values. With observations of real data, it seems likely that initial pay levels will vary across performance categories, reflecting past pay policies, demographics, and performance distributions. While quite easy to observe in practice, pay-performance distributions are likely quite variable, so no obvious method exists to simulate them for our example. Our decision to begin with a uniform pay distribution across categories simplifies the presentation but does not otherwise reduce the generalizability of our approach.

Step 2: Determine Turnover Probabilities

The second step in the making explicit of organizational characteristics and assumptions (i.e., the first major phase in Figure 1) is to estimate the probability of separation at each performance level for each pay strategy. This step defines the key link between performance-based pay and workforce composition. For practitioners, this may represent the most novel element of the model, yet we believe it is quite feasible. We describe several methods for estimating these probabilities.

Estimation using existing research literature

Perhaps the most straightforward approach is to refer to existing empirical findings. For our hypothetical example, we use the performance level/pay strategy specific separation results generated by Trevor et al. (1997). Professionals employing utility analysis likely would prefer to access separation probabilities from a study of an employee population that resembled their own employees in terms of occupations, industry, and demographics. To date, however, the Trevor et al. (1997) study is the only published work from which the performance level/pay strategy specific separation probabilities can be estimated. While future research providing such information for different employee populations would be helpful, in their absence, the Trevor et al. (1997) results offer a useful starting point.

Estimation using organizational data

A second option for generating the performance level/pay strategy specific separation probabilities that are necessary for the cost-benefit analysis would be for professionals to estimate them using their own organization's data. In most companies, separation rates are customarily calculated for entire job categories and are seldom broken down by performance levels. Even when separation rates are reported by performance levels, they are rarely further broken down to reflect pay growth. Yet, if yearly individual-level information on performance, pay level, and separation is available, it can rather easily be converted into the required separation probabilities estimates.

First, professionals can compute each employee's average pay growth and average employee performance over a specified time period (e.g., over the last three years). These relatively continuous data can then be used to slot employees into performance level/pay strategy categories, such as Table 1's 27 categories that were created from all combinations of three pay strategies and nine performance levels. This approach would be repeated for all appropriate performance level and pay growth combinations, thus yielding counts of employees that fit each category. After compiling these counts, the second step would be simply to divide each category's number of voluntary separations by the number of employees in that category. This would yield the estimates of the separation probabilities specific to each performance level/pay strategy combination that are necessary for conducting the cost-benefit analysis of performance-based pay.

While relatively simple to describe, estimating category-specific separation probabilities from one's own organization involves two potentially difficult hurdles. First, to estimate the separation probabilities with any degree of reliability, there must be an adequate number of employees in the categories of interest. If the number of employees in a given category is low, then the resultant average rate of turnover may be strongly influenced by sampling error rather than reflecting an accurate estimate of that category's true turnover likelihood (e.g., a category with one employee mandates an unrealistic separation probability estimate of either one or zero). Thus, the HR professional or I/O psychologist must be working with relatively few categories and/or with large employee populations. A second serious problem with the approach described above is that it will produce separation probabilities that are likely to be confounded by other factors that are related to turnover, performance, and pay growth, such as pay level, age, gender, and tenure with the organization. Hence, though computing performance level/pay strategy specific separation probabilities for one's own organization is relatively simple, its value may be limited.

Fortunately, two statistical methods are available for dealing with the confounding and employee-per-category problems. While both of these methods require a statistical package and reasonable statistical sophistication, I/O psychologists may well have been exposed to one or both of the methods. If not, their training still may well have provided them with a methodological foundation sufficient to allow them to learn the techniques, particularly with the advances in user-friendly statistical software. Alternatively, HR professionals or I/O psychologists could simply hire a consultant to assist with the analyses.

Logistic regression and survival analysis can be used to estimate separation probabilities. Both explicitly account for the potential confound described above by statistically controlling for the effects of these other variables. The analyses yield partial coefficients that are net of the effects of the potentially confounding variables. The partial coefficients are then used to compute separation probabilities needed to conduct the cost-benefit analysis. Both methods also exploit the full range of the relatively continuous salary growth and performance data, rather than requiring pre-established categories that necessarily result in a loss of information. Logistic regression estimates the probability of separation over a specified time period. Survival analysis (Kalbfleisch & Prentice, 1980) computes the probability of survival (i.e., not separating) over a specified time span, and accounts for the length of time an individual stays before leaving the organization. In other words, survival analysis specifically models how long an individual remains with an employer before leaving, whereas logistic regression models whether a person leaves or not. While both methods are appropriate for estimating the separation probabilities specific to the performance level/pay strategy combinations of interest, each offers advantages under certain circumstances (for a complete discussion of this issue, see Morita, Lee, & Mowday, 1993). Our Appendix describes the use of survival analysis to calculate the required separation probabilities that are specific to each of our performance level/pay strategy combinations.

Estimated separation probabilities for the example.

For our example, we used the survival analysis results reported in Trevor et al. (1997), which estimated a survival model from data on a sample of exempt employees in one organization. The analysis produced a mathematical function describing survival probabilities as a function of salary growth and performance, which we present in the Appendix. Substituting a specific salary growth amount and performance level into the equation produces an estimated survival probability that is appropriate for that performance level and salary growth combination. Thus, we used the equation reported in Trevor et al.'s (1997) Table 4 (p. 54) to compute the separation probability (1.0 minus the survival probability), for each performance category under each pay strategy, at the end of our example's 4-year period. The estimated separation probabilities are presented in the top part of Table 2.

Table 2

Turnover Probabilities, and Estimate Number of Retained and Replaced Employees

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Number of employees	**60**	**97**	**1171**	**1090**	**1667**	**672**	**317**	**46**	**23**	5143
Turnover Probabilities[1] (Probability of leaving the organization by 2007)										
Pay Strategy 1	**0.96**	**0.65**	**0.38**	**0.25**	**0.21**	**0.22**	**0.27**	**0.41**	**0.66**	
Pay Strategy 2	**0.96**	**0.65**	**0.38**	**0.25**	**0.21**	**0.14**	**0.11**	**0.11**	**0.14**	
Pay Strategy 3	**0.99**	**0.88**	**0.60**	**0.35**	**0.21**	**0.14**	**0.11**	**0.11**	**0.14**	
Retained Employees (2007)										
Pay Strategy 1	2	34	726	818	1317	524	231	27	8	3687
Pay Strategy 2	2	34	726	818	1317	578	282	41	20	3818
Pay Strategy 3	1	12	468	709	1317	578	282	41	20	3428
Replaced Employees (2004 - 2007)[2]										
Pay Strategy 1	58	63	445	273	350	148	86	19	15	1457
Pay Strategy 2	58	63	445	273	350	94	35	5	3	1326
Pay Strategy 3	59	85	703	382	350	94	35	5	3	1716

Notes: 1. These values were based on analyses from the Trevor et al. (1997) study. Those performing their own analyses would need to complete the table with their own company-specific data, or use approximations from the Trevor et al. results. See the Appendix for how we used the Trevor et al. results to obtain our values above.
2. Recall that we are evaluating the effects of the different pay policies going into effect at the end of 2004. Thus, while our data are based on the state of the workforce at the end of 2003, we are evaluating the effects of the programs in 2004-2007.
3. Data provided by the user **are in bold.**

We caution that our use of the Trevor et al. (1997) survival analysis provides reasonable separation probability estimates, rather than definitive ones. It is certainly probable that other factors could also influence the probability of turnover. For example, equity theory suggests that even when high performers receive the same pay increase (such as under Pay Strategy 2 and Pay Strategy 3), their turnover likelihoods may differ as a function of how referent others (e.g., low performers) are compensated. Our approach does not take this into consideration. Thus, the reader should keep in mind the imperfections associated with relying on any single study, model of turnover, or data set to estimate turnover probabilities.

Step 3: Determine Performance Distribution and Number of Separations

So far, we have established the pay increase that individuals in each performance level will receive under the different pay policies, and we have subsequently established the separation probabilities for each performance level/pay strategy category. Next, we need to project the number of separations in each performance level/pay strategy category over time. We specified our initial hypothetical employee group (those at the end of year 2003) to mirror in size and performance distribution the 5,143 employees analyzed by Trevor et al. (1997), which is shown in Table 2 (in actual organizations, the initial number of employees in each performance category would be identified through a straightforward count). We then multiplied the initial number of employees in each performance level/pay strategy category by the appropriate separation probability. Table 2 presents the resultant category-specific numbers of employees that separated (and will need to be replaced) and employees retained.

At this point, a traditional analysis of total separations would likely lead to a decision to adopt pay strategy 2, the moderately-aggressive policy through which performers above the midpoint receive higher pay increases. As Table 2 indicates, the number of separations over the four-year analysis period is 1,326 for pay strategy 2, while it is 1,457 for pay strategy 1 and 1,716 for pay strategy 3. Based only on separation rates, pay strategy 3 seems the least attractive policy. However, such conclusions are simplistic and superficial from a cost/benefits perspective; a more sophisticated and meaningful inference regarding the implications of the three pay strategies requires an analysis incorporating critical financial data.

Estimating the Cost of Pay-For-Performance Plans

Step 4: Determine Movement Costs

In steps one through three, we specified the pay-for-performance options, the estimated separation probabilities, and the subsequent numbers of separations and necessary replacements from each performance level/pay strategy combination. Hence, one key financial outcome to be considered is the projected cost of employee movements into and out of the workforce under each pay policy. As we see in Table 2, relative to the retention effects of simply providing everyone with the same salary increase (pay strategy 1), pay strategy 2 reduces overall separations, while pay strategy 3 increases them. We next translate these projected separations and replacements into financial costs.

We refer to the combined costs of employee separations and replacement acquisitions as movement costs. These costs include direct expenses, such as separation costs (e.g., exit interview, separation pay), replacement costs (e.g., advertising, travel expenses, interviewing and testing candidates), and training costs (e.g., informational literature costs, paying trainers). Movement costs also include indirect expenses, such as the lower productivity of new employees as they learn the job, time spent by managers having to supervise new employees more directly, and diminished productivity of veteran employees as they mentor and help new employees (Cascio, 2000). While such costs are not standard elements of traditional accounting systems, organizations increasingly employ software and reporting algorithms that calculate such metrics as turnover costs, costs per hire, etc. If these are available, one can simply multiply the relevant cost by the number of separations and/or replacements that emerge under each pay strategy.

Data available to calculate movement costs varies widely across companies. When movement costs are not readily available from the organization, one can turn to research. For example, Solomon (1988) suggested that movement costs range from 1.5 to 2.5 times the annual salary paid for a job (Solomon, 1988), while Johnson (1995) suggested that movement costs range from 93% to 200% of the position's salary. In our example, we estimated the movement cost associated with each separation as two times the average salary of all employees in the year of the separation (note that average salary will vary according to pay strategy). We also assumed that each separation is replaced, and thus we combined all separation and acquisition costs into a single estimate labeled movement costs. Should replacement not be expected, such as during a downsizing, separation cost estimates should be applied to the number of separations, and replacement acquisition costs should be applied to the number of replacements (Boudreau & Berger, 1985).

Table 3 provides the necessary information to estimate movement costs for our example. At the top of the table is the workforce's average salary in 2003 and in 2007 under each of the three pay strategies. As noted above, we multiplied this salary by 2.0 to estimate the average movement costs for each separation, which is shown for years 2003 and 2007. We then subtracted the 2003 average movement cost from the 2007 average movement cost and divided by four to get yearly movement cost increase, which we added to the 2003 average movement cost to get the 2004 average movement cost. This was added to the 2007 average movement cost and the sum was divided by two to compute the average (2004-2007) movement cost per separation. Table 3 also provides the total projected number of separations/replacements from Years 2004 to 2007, which were calculated in Table 2. Total movement costs for each pay strategy over the four-year period were then calculated by multiplying each pay strategy's total number of projected separations/replacements by each pay strategy's average movement cost per separation/replacement.

Table 3

Estimated Four-Year Movement Costs Under Different Pay Strategies

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Salary			
2003	$47,983	$47,983	$47,983
2007	$56,133	$56,914	$55,966
Movement Cost Multiplier (cost of separation as multiple of salary; same for all three Pay Strategies)	**2.0**		
Average Movement Costs (per separation)			
2003	$95,966	$95,966	$95,966
2007	$112,266	$113,828	$111,932
Yearly Increase in Average Movement Cost	$4,075	$4,466	$3,992
2004 Average Movement Cost	$100,041	$100,432	$99,958
Average Movement Cost (2004 - 2007)	$106,154	$107,130	$105,945
Number of Separations	1,457	1,326	1,716
Total Movement Costs[1]	$154,666,378	$142,054,380	$181,801,620

Notes: 1. Total Movement Costs were calculated assuming a linear growth in movement costs and an equal number of separations in each year. Thus, Total Movement Costs could be calculated as the number of separations times the average 2004 - 2007 movement costs. For simplicity, we assumed a constant rate of movement cost increase over time. This could easily be modified if an organization projected very significant increases or decreases in costs per movement in a given year, but such large discontinuities seem unlikely.
2. Data provided by the user **are in bold.**

Table 3's total estimated movement costs were $154.67 million, $142.05 million, and $181.80 million for pay strategies 1, 2, and 3, respectively. Compared to pay strategy 1 (giving equal pay increases to everyone), the turnover reduction associated with the policy of linking pay and performance for high performers (pay strategy 2) saves $12.61 million in movement costs over four years. Linking pay and performance for both high and low performers (pay strategy 3), however, creates additional separations among low performers and thus incurs four-year movement costs of $27.13 million and $39.75 million more than those incurred through pay strategies 1 and 2, respectively.

Some of these costs would be evident with standard accounting tools, to the extent that they represent "out-of-pocket" costs such as fees to search firms or consultants providing exit interviews. However, as mentioned above, many of these costs (e.g., staff time spent in processing separations and acquisitions) are "opportunity costs," and only a portion of these savings (costs) would be recorded by the accounting system. Thus, our analytical approach offers the advantage of a more complete cost analysis for incentive pay strategies. Still, movement costs represent only one of the crucial financial implications of using pay-for-performance to manage performance and turnover. Hence, we next address the pay strategies' substantial implications for differences in costs associated with pay levels, benefits, and other service costs.

Step 5: Estimate Future Service Costs

Service costs are the total costs required to retain and support the work force, and thus include pay and benefits (Boudreau & Berger, 1985), the latter of which is typically the largest service cost component other than pay. In some cases, service costs may vary with employee performance. For example, there may be significant bonuses or stock options, or higher performers may use significantly more materials or resources than lower performers. In these cases, which would tend to be of more relevance in executive populations, such variability in service costs should also be taken into account. Absent such factors, estimating service costs simply involves adjusting projected salary levels upward to reflect additional service costs (i.e., benefits), multiplying the resulting values by the number of employees in each year, and summing the products across years. Because we define total service costs as salary plus benefits in our example, we estimate each year's service costs by estimating the ratio of total remuneration (employee benefits plus salary) to salary, and then multiplying this ratio by projected salary levels under each pay policy.

In Table 3 we had established, for each pay strategy, the average salary levels for the full work force in 2003 and 2007. Because we assumed that benefits were 37% of salary (U.S. Department of Labor, 2001), we multiplied Table 3's average salary levels by 1.37 to reflect the

2003 and 2007 average service costs for each pay strategy (see Table 4). Using the assumption that service costs increased linearly from 2003 to 2007, we then computed, for each of the three pay strategies, (a) the average service cost increase (2007 service cost minus 2003 service cost, divided by four), (b) 2004 service cost (2003 service cost plus the average service cost increase), (c) the average 2004-2007 service cost (2004 service cost plus 2007 service cost, divided by two), and (d) the total 2004-2007 service cost (average 2004-2007 service cost times four, the number of years in our simulation, times 5143, the total number of employees in each year).

Table 4
Estimated Four-Year Service Costs Under Different Pay Strategies

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Service Cost Multiplier (per employee)	**1.37**	**1.37**	**1.37**
Average Service Cost			
2003	$65,737	$65,737	$65,737
2007	$76,902	$77,972	$76,673
Yearly Increase in Service Costs	$2,791	$3,059	$2,734
2004 Average Service Cost	$68,528	$68,796	$68,471
Average Service Cost (2004 - 2007)	$72,715	$73,384	$72,572
Total Service Costs (2004 - 2007)	$1,495,892,980	$1,509,655,648	$1,492,951,184

Notes: 1. Average service cost per employee is assumed to equal 1.37 times Table 3's average salary under each pay strategy. Total costs were calculated assuming a linear growth in service costs. Thus, it was estimated to equal the number of employees times the number of years times the average service costs (2004-2007).
2. Data provided by the user **are in bold.**

An implication of our decision to use the workforce average service costs to estimate total service costs is that it implicitly assumes that replacement employees will be paid at the average level of the workforce they enter. The framework of this model can certainly accommodate other assumptions (e.g., stronger pay-performance links will attract better performers who will be paid more), and would allow practitioners to incorporate such data when appropriate. We adopted the workforce-average assumption for simplicity.

Pay strategy 2 yielded the highest service costs; it is projected to cost $13.76 million more than pay strategy 1 (no performance-pay relationship). Under pay strategy 2, pay is always equal (for performers at or below the performance midpoint) or higher (for performers above the midpoint) than pay in strategy 1. Pay strategy 3 raises the pay for higher performers, but also lowers pay for lower performers, resulting in costs of $2.94 million less over four years than pay strategy 1, and $16.70 million less than pay strategy 2.

Service costs (i.e., pay and benefits) are highly visible to standard accounting systems. In fact, one could argue that they are the most visible elements of human capital in standard accounting. Thus, if standard accounting were used to evaluate these pay policies, the costs shown in Table 4 would likely be quite evident, and would perhaps suggest an argument for pay strategy 3 to organizational constituents who rely on accounting information for their decisions. Given that the movement costs analysis suggested pay strategy 3 as the least economical approach, however, it is clear that relying on only a single type of cost information may well provide an inaccurate basis for a decision. When we do aggregate the total movement and total service cost data from Tables 3 and 4, we see that pay strategy 3 is the most expensive, costing over $23 million more than pay strategy 2 and over $24 million more than pay strategy 1.

Consequently, from a cost-based perspective, we might conclude that undertaking an aggressive pay-for-performance system to "win the talent war" is not worth the investment. We instead caution that such an inference (and any decisions based on it) is at the least premature and is potentially detrimental to the organization. High performers provide greater value than do low performers, and any assessment of an HR program that differentially affects the performance distribution of the workforce must account for this. HR investments must be examined for both their "efficiency" and "effectiveness" (Boudreau & Ramstad, 2003b). Hence, having addressed the movement and service costs implications of the three pay strategies' effects on turnover, we next turn to the strategies' implications for workforce's value, an often overlooked but absolutely essential consideration when assessing the financial practicality of human resource interventions.

Estimating the Value of Pay-For-Performance Plans

Step 6: Determine Service Value

Although our analyses have focused on the cost implications of the pay-for-performance strategies, such strategies also can produce value through the elimination of poor performers (and their subsequent replacement by average performers), and, in particular, the retention of high performers, whose retention is especially sensitive to pay-for-performance effects (Trevor et al., 1997). Moreover, when differences in individual performance are high (i.e., when a high performer is worth much more to the organization than an average performer), retaining top employees and eliminating poor employees may yield value that far outweighs the associated costs (Boudreau & Berger, 1985; Boudreau, 1991; Boudreau & Ramstad, 1999; 2003a; 2003b).

To examine the potential effects of performance-based pay on workforce value, we need to estimate the dollar value of individual performance variation. This will allow us to estimate the effect that changes in the workforce's performance distribution will have on workforce value. Our data provide estimates of changes in the performance ratings, so we must convert ratings to dollar values. This conversion method requires two components (Boudreau & Berger, 1985): (a) the dollar value of the average performance level; and (b) the incremental value of deviations from that average performance level.[3]

We employed the Schmidt and Hunter (1983) approach, which assumes that the value of the average performance level would equal 1.754 times the average wage at that level. For the 2003 work force, we multiplied Table 3's average salary of $47,983 by 1.754 to obtain a service value of $84,162 per person. For the 2007 work force, consistent with the estimate of average service costs above, we estimated average salary as that which would have been produced by four years of average salary increases, beginning in 2004. As noted in Table 3, the average 2007 salary under pay strategy 1, which allocates average salary increases across the performance distribution, is estimated to be $56,133. Multiplying this salary by 1.754 produces an average work force value estimate of $98,457 per person. These 2003 and 2007 average service value estimates are shown in "average service value" section of Table 5.

Table 5
Computations for Estimating Individual Service Value at Each Performance Level

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5
Number of employees	60	97	1171	1090	1667	672	317	46	23
Mean Performance		2.764							
Standard Dev. of Performance		0.668							
Z-Score of Performance Ratings	-2.641	-1.892	-1.144	-0.395	0.353	1.102	1.850	2.599	3.347
Average Service Value (assumed to equal 1.754 * average salary)									
2003	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162
2007	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457
Incremental Service Value **SDy =0.30**									
2003	-$38,017	-$27,235	-$16,468	-$5,686	$5,081	$15,863	$26,631	$37,412	$48,180
2007	-$44,474	-$31,861	-$19,265	-$6,652	$5,944	$18,558	$31,154	$43,767	$56,363
Incremental Service Value **SDy =0.60**									
2003	-$76,034	-$54,470	-$32,936	-$11,372	$10,163	$31,726	$53,261	$74,825	$96,359
2007	-$88,948	-$63,722	-$38,530	-$13,304	$11,889	$37,115	$62,308	$87,534	$112,726
Incremental Service Value **SDy =0.90**									
2003	-$114,051	-$81,705	-$49,403	-$17,058	$15,244	$47,590	$79,892	$112,237	$144,539
2007	-$133,423	-$95,583	-$57,795	-$19,955	$17,833	$55,673	$93,461	$131,301	$169,089
Total Individual Service Value (SDy = 30%)[1]									
2003	$46,145	$56,927	$67,694	$78,476	$89,243	$100,025	$110,793	$121,574	$132,342
2007	$53,983	$66,596	$79,192	$91,805	$104,401	$117,015	$129,611	$142,224	$154,820
Total Individual Service Value (SDy = 60%)									
2003	$8,128	$29,692	$51,226	$72,790	$94,325	$115,888	$137,423	$158,987	$180,521
2007	$9,509	$34,735	$59,927	$85,153	$110,346	$135,572	$160,765	$185,991	$211,183
Total Individual Service Value (SDy = 90%)									
2003	-$29,889	$2,457	$34,759	$67,104	$99,406	$131,752	$164,054	$196,399	$228,701
2007	-$34,966	$2,874	$40,662	$78,502	$116,290	$154,130	$191,918	$229,758	$267,546

Notes: 1. Total Individual Service Value is computed as the Average Service Value plus the Incremental Service Value, shown in the top portion of this table.
2. Data provided by the user are in bold.

For the second component necessary to estimate the value associated with each employee, we needed an estimate for the value of each performance level above and below the average. Combined with the estimate for the average value of individuals' performance, this will allow us to calculate the value of each of the nine performance levels, in both 2003 and 2007. In this study, and probably characteristic of most organizations, we had no direct estimates of the dollar value of particular performance levels. Hence, we used an estimation approach typical of utility analysis studies (e.g., Boudreau, 1991; Boudreau & Ramstad, 2003b). Utility analysis typically employs an estimate of the value of a one-standard-deviation difference in employee value, referred to as SDy, with SDy often approximated as equal to a given percentage of salary (Boudreau, 1991; Cascio, 2000). Thus, someone who performs one standard deviation above average (i.e., someone who is in the 84th percentile of performance) is estimated to be worth more than an average performer by a value equal to SDy. Using the SDy term, we can compute the value of each performance category relative to the average.

A recurring problem with using SDy is that it is unlikely to be estimated precisely (Boudreau, 1991; Cascio, 2000). Furthermore, its impact on final estimates of the value of a utility estimate is often quite significant (Boudreau, 1991). Thus, we investigated three potential values. As a very conservative approach, we assumed that SDy would equal 30% of average salary. This is substantially less than Schmidt and Hunter's (1983) 40% recommendation, which has been characterized as a conventional benchmark (Becker & Huselid, 1992), a safe estimate (Schmidt, Hunter, Outerbridge, & Trattner, 1986), and a conservative estimate (Judiesch, Schmidt, & Mount, 1992). We also used 60% of average salary as a somewhat conservative estimate, and we used 90% of average salary as what we believe to be a more realistic estimate.[4] In other words, our three estimates suggest that an employee performing better than 84 percent of the employee population is worth 30% of salary, 60% of salary, or 90% of salary more to the organization than an average performer (i.e., someone performing at the 50th percentile) in the same job.

In order to move from these SDy estimates to estimates of each employee's service value, we first used the observed distribution of employee performance to compute the standardized z-score corresponding to each of the nine performance ratings. This transformation, accomplished through subtracting the mean performance score from each performance category rating and then dividing by the performance standard deviation, produces a performance distribution with a mean of zero and a standard deviation of one. For example, performance category 1.5 received a z-score of -1.89 through subtracting the average performance rating of 2.764 from 1.5 and dividing by the standard deviation of 0.668. The z-scores, which represent the number of standard deviations that each performance category rating deviates from the performance mean, are listed in the fifth row of data in Table 5.

We assumed that the z-scores associated with each raw performance score would remain constant from 2003 to 2007. That is, although the actual distribution of workers across performance categories changes from 2003 to 2007, we assumed that the value of performance at each performance level did not change. For example, a performance rating of 4 in 2003, which was 1.850 standard deviations above the mean in 2003, provided value to the employer equal to mean performance's value plus the product of 1.850 and SDy. We assumed, regardless of the actual number of employees who received a score of 4 in 2007, the financial value of an individual with a performance rating of 4 in that year would be equal to 2007 mean performance's value plus the product of 1.850 and SDy.

For 2003, we estimated average salary as $47,983 (from Table 1), producing SDy estimates of $14,395 (i.e., 0.3 * $47,983), $28,790 (i.e., 0.6 * $47,983) and $43,185 (i.e., 0.9 * $47,983) for the 30%, 60% and 90% SDy scenarios, respectively. For 2007, estimated average salary was $56,133 (from Table 1), producing, at the 30%, 60%, and 90% SDy scenarios, estimated SDy levels of $16,840 (i.e., 0.3 * $56,133), $33,680 (i.e., 0.6 * $56,133), and $50,520 (i.e., 0.9 * $56,133). Multiplying these SDy estimates (i.e., the appropriate dollar value of a one standard deviation performance difference) by the z-scores (i.e., the number of standard deviations the performance category is from the mean) produced the "incremental" (beyond the average) dollar values corresponding to each performance rating level for each SDy assumption (see Table 5). Thus, under the 60% assumption in 2007, an employee at performance level 5.0 is worth $112,726 more than an average employee (i.e., $56,133 * 0.60 * 3.347). The sums of the average service values for the workforce, and the incremental service values for each performance category, produced the individual service values for each performance category that are reported in the bottom section of Table 5. Thus, the last six lines of data in Table 5 represent, for each unique combination of performance level (1.0 – 5.0 at half point intervals), year (2003 and 2007), and SDy scenario (30%, 60%, and 90%), the individual service value for each employee.

With individual service values determined for both 2003 and 2007, we can now compute the total service value for the workforce under each of the three pay strategies. For 2003 (for all three pay strategies), we calculated the total service value of the workforce by multiplying each performance category's individual service value by the corresponding quantity of employees in the performance category, and adding the products. Thus, for example, Table 5's individual service value of $115,888 for SDy = 60% and performance = 3.5 in 2003 is multiplied by 672 (the number of employees in that performance category) to yield the $77,876,736 figure in Table 6 (under SDy = 60% and performance = 3.5). This $77,876,736 is then added to the similarly computed values for the other eight performance categories to produce, when SDy = 60%, Table 6's total 2003 service value of $432,351,857. This is our estimate of what the workforce is worth to the employer in 2003 under the assumption that being one standard deviation above average in performance is worth 60% of an average performer's salary. We note that the total service values are the same in 2003 regardless of pay strategy (although they do differ across SDy assumptions) because the three pay strategies had yet to result in the different performance-specific turnover patterns that begin in 2004.

Table 6

Computing Total Service Value (2003 Employees)

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Number of employees	60	97	1171	1090	1667	672	317	46	23	5143
2003 Total Service Value										
SDy = 30%	$2,768,700	$5,521,919	$79,269,674	$85,538,840	$148,768,081	$67,216,800	$35,121,381	$5,592,404	$3,043,866	$430,072,965
SDy = 60%	$487,680	$2,880,124	$59,985,646	$79,341,100	$157,239,775	$77,876,736	$43,563,091	$7,313,402	$4,151,983	$432,351,857
SDy = 90%	-$1,793,340	$238,329	$40,702,789	$73,143,360	$165,709,802	$88,537,344	$52,005,118	$9,034,354	$5,260,123	$434,631,219

Note: The total service values are the same in 2003 regardless of pay strategy (although they do differ across SDy assumptions) because the three pay strategies had yet to result in the different performance-specific turnover patterns that begin in 2004.

For 2007, calculation of the total service value of the workforce is slightly more complex, as the computations for those employees retained over the four-year analysis differ from the computations required for those hired as replacements during the four-year period. For the retained employees, 2007 total service value calculation closely resembles the approach to 2003, where Table 5's 2003 individual service values for each SDy level and performance category combination were multiplied by the quantity of retained employees for each performance category, and these products were summed. In 2007, however, the three pay strategies' different effects on performance-specific turnover result in pay strategy-specific numbers of retained employees in each performance category. Consequently, we need to conduct the individual service value by employee quantity multiplications separately for each pay strategy to get the 2007 estimates. Thus, Table 5's 2007 individual service values for each SDy level and performance category combination were multiplied by the quantity of retained employees for each performance category under each pay strategy, and these products were summed. For example, Table 5's individual service value of \$129,611 for SDy = 30% and performance = 4.0 in 2007 is multiplied by 231, 282, and 282 (the number of retained employees in that performance category under the three pay strategies, as listed in Table 7) to yield the \$29,940,141, \$36,550,302, and \$36,550,302 figures in Table 7 (under SDy = 30%, performance = 4.0, and pay strategies 1, 2, and 3, respectively). Thus, the final nine rows of data in Table 7 chronicle, for each SDy and pay strategy combination, the combined service value of all retained employees in 2007 at each performance level. The final column for each of these nine rows provides total service values across performance categories.

Table 7

Total Service Value of Retained Employees (2007)

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Retained Employees										
Pay Strategy 1	2	34	726	818	1317	524	231	27	8	3687
Pay Strategy 2	2	34	726	818	1317	578	282	41	20	3818
Pay Strategy 3	1	12	468	709	1317	578	282	41	20	3428
Total Service Value (2007)										
SDy = 30%										
Pay Strategy 1	$107,966	$2,264,264	$57,493,392	$75,096,490	$137,496,117	$61,315,860	$29,940,141	$3,840,048	$1,238,560	$368,792,838
Pay Strategy 2	$107,966	$2,264,264	$57,493,392	$75,096,490	$137,496,117	$67,634,670	$36,550,302	$5,831,184	$3,096,400	$385,570,785
Pay Strategy 3	$53,983	$799,152	$37,061,856	$65,089,745	$137,496,117	$67,634,670	$36,550,302	$5,831,184	$3,096,400	$353,613,409
SDy = 60%										
Pay Strategy 1	$19,018	$1,180,990	$43,507,002	$69,655,154	$145,325,682	$71,039,728	$37,136,715	$5,021,757	$1,689,464	$374,575,510
Pay Strategy 2	$19,018	$1,180,990	$43,507,002	$69,655,154	$145,325,682	$78,360,616	$45,335,730	$7,625,631	$4,223,660	$395,233,483
Pay Strategy 3	$9,509	$416,820	$28,045,836	$60,373,477	$145,325,682	$78,360,616	$45,335,730	$7,625,631	$4,223,660	$369,716,961
SDy = 90%										
Pay Strategy 1	-$69,932	$97,716	$29,520,612	$64,214,636	$153,153,930	$80,764,120	$44,333,058	$6,203,466	$2,140,368	$380,357,974
Pay Strategy 2	-$69,932	$97,716	$29,520,612	$64,214,636	$153,153,930	$89,087,140	$54,120,876	$9,420,078	$5,350,920	$404,895,976
Pay Strategy 3	-$34,966	$34,488	$19,029,816	$55,657,918	$153,153,930	$89,087,140	$54,120,876	$9,420,078	$5,350,920	$385,820,200

Having computed 2007 service value for retained employees, we next address the 2007 value of those employees hired to replace the employees that separated during the 2004-2007 window. These replacement employees were assumed to have an individual service value equal to the average individual service value of retained employees under pay strategy 1 for each of the SDy assumptions. Thus, for example, Table 8's average individual replacement employee service value of $101,594 when SDy = 60% was computed by dividing Table 7's total retainee service value of $374,575,510, which is under pay strategy 1 with SDy = 60%, by 3687, which is Table 7's total retainees under pay strategy 1. We note that using pay strategy 1's retainee service value for all replacements assumes that the recruiting effectiveness and job performance of replacement employees are not affected by the compensation system. Because the average service value of retained employees under pay strategies 2 and 3 is greater than the average service value of employees retained under pay strategy 1, this provides a conservative estimate of replacement service value under the two pay strategies with pay-for-performance links. The total service value of replacement employees for each pay strategy and SDy combination is equal to the pay strategy-specific number of replacements times the SDy-specific average service value. These totals are reported in the bottom three rows of data in Table 8.

Table 8
Service Value of Replacement Employees (2007)

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Service Value			
SDy = 30%	$100,025	$100,025	$100,025
SDy = 60%	$101,594	$101,594	$101,594
SDy = 90%	$103,162	$103,162	$103,162
Number of Separations (2004-2007)	1457	1326	1716
Total Service Value of Replacements (2007)			
SDy = 30%	$145,736,425	$132,633,150	$171,642,900
SDy = 60%	$148,022,458	$134,713,644	$174,335,304
SDy = 90%	$150,307,034	$136,792,812	$177,025,992

Note: We are using the conservative assumption that replacement employees will have the service value of employees under the first pay strategy. Our approach implicitly assumes that the pay strategy has no effect on recruitment or job performance of new employees. If we assumed that new employees had service values equal to the average service values of employees under the new pay strategies, then the total service value of replacements would be higher under pay strategies 2 and 3.

Finally, Table 8's service values of the replacements and Table 7's service values of retained employees were added to produce the estimated 2007 total service value for each pay strategy and SDy level combination, as shown in Table 9. We used these 2007 total service values, as well as the 2003 total service values from Table 6, to compute total service value across all years in Table 10. As we had done with total service costs computations, we calculated the four-year stream of service value levels by assuming that service value rose linearly in each performance category between 2003 and 2007. Thus, for each pay strategy and SDy combination, we computed (a) the average service value increase (2007 service value minus 2003 service value, divided by four); (b) 2004 service value (2003 service value plus the average service value increase); (c) the average 2004-2007 service value (2004 service value plus 2007 service value, divided by 2); and (d), the total 2003-2007 service value (average 2003-2007 service value, times four, the number of years in our simulation).

Table 9
Total Service Value of the 2007 Workforce

	Value of Retained Employees	+	Value of Replaced Employees	=	Total Value (2007)
SDy = 30%					
Pay Strategy 1	$368,792,838	+	$145,736,425	=	$514,529,263
Pay Strategy 2	$385,570,785	+	$132,633,150	=	$518,203,935
Pay Strategy 3	$353,613,409	+	$171,642,900	=	$525,256,309
SDy = 60%					
Pay Strategy 1	$374,575,510	+	$148,022,458	=	$522,597,968
Pay Strategy 2	$395,233,483	+	$134,713,644	=	$529,947,127
Pay Strategy 3	$369,716,961	+	$174,335,304	=	$544,052,265
SDy = 90%					
Pay Strategy 1	$380,357,974	+	$150,307,034	=	$530,665,008
Pay Strategy 2	$404,895,976	+	$136,792,812	=	$541,688,788
Pay Strategy 3	$385,820,200	+	$177,025,992	=	$562,846,192

Table 10
Computing Four Year Total Service Value

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
SDy = 30%			
2003 Service Value	$430,072,965	$430,072,965	$430,072,965
2007 Service Value	$514,529,263	$518,203,935	$525,256,309
Average Service Value Increase	$21,114,075	$22,032,743	$23,795,836
2004 Service Value	$451,187,040	$452,105,708	$453,868,801
Avg. (2004 - 2007 Service Value)	$482,858,152	$485,154,822	$489,562,555
Total Service Value (2004-2007)	$1,931,432,608	$1,940,619,288	$1,958,250,220
SDy = 60%			
2003 Service Value	$432,351,857	$432,351,857	$432,351,857
2007 Service Value	$522,597,968	$529,947,127	$544,052,265
Average Service Value Increase	$22,561,528	$24,398,818	$27,925,102
2004 Service Value	$454,913,385	$456,750,675	$460,276,959
Avg. (2004 - 2007 Service Value)	$488,755,677	$493,348,901	$502,164,612
Total Service Value (2004-2007)	$1,955,022,708	$1,973,395,604	$2,008,658,448
SDy = 90%			
2003 Service Value	$434,631,219	$434,631,219	$434,631,219
2007 Service Value	$530,665,008	$541,688,788	$562,846,192
Average Service Value Increase	$24,008,447	$26,764,392	$32,053,743
2004 Service Value	$458,639,666	$461,395,611	$466,684,962
Avg. (2004 - 2007 Service Value)	$494,652,337	$501,542,200	$514,765,577
Total Service Value (2004-2007)	$1,978,609,348	$2,006,168,800	$2,059,062,308

Under all assumptions about SDy, the 2007 and total service values are lowest when giving all employees average pay increases (pay strategy 1), are higher when giving high performers high pay increases and all others average increases (pay strategy 2), and are highest when the pay-for-performance link was strongest (pay strategy 3). Compared to pay strategy 1, which gives all employees average pay increases, pay strategy 2 prompts more high-performing and highly-paid employees to stay, and their value enhances the work force. Pay strategy 3 augments this effect by encouraging the turnover of low performers, who subsequently are replaced with workers whose expected value is that of average workers under pay strategy 1.

Hence, whereas our cost analysis suggested that pay strategy 3 was the least effective and pay strategy 1 was the most effective, our analysis of workforce value indicates the exact opposite. Obviously, relying only on either cost or value estimates would be shortsighted. The critical question is whether the service value benefits of a strong pay-for-performance link outweigh the costs (Boudreau, 1991; Boudreau & Ramstad, 2003a; 2003b).

Step 7: Determining the Final Utility—Is Pay-for-Performance Worth it?

At this point, we return to the flow chart in Figure 1 and the question that motivated this research effort: Is it worth it to use pay-for-performance in an attempt to win the war for talent? To speak to this, we began by specifying three pay plan strategies and estimating the subsequent turnover probabilities and performance distributions we would expect under each. Using this turnover and performance information, we then addressed costs for each pay plan through the estimation of expenses associated with employee movement out of and into the workforce and with the pay and benefits for the workforce. Having estimated costs, we turned to the benefits dimension of the cost-benefit analysis and estimated the value of the retained workforce and of the replacement employees. Thus, we have estimated the three components for the decision of whether pay-for-performance makes sense in our example: (a) the four-year stream of movement costs; (b) the four-year stream of service costs; and (c), the four-year stream of service value. Now, we combine these components to estimate the relative value of the three pay strategies by taking the stream of service value and subtracting the stream of service costs and movement costs (Boudreau & Berger, 1985). The relevant amounts are summarized in Table 11 for each pay strategy and SDy assumption combination.

Table 11
Computation of Four Year Investment Value of Different Pay Strategies (in $millions)

	Service Value (in $millions)	-	Service Costs (in $millions)	-	Movement Costs (in $millions)	=	Four Year Value (in $millions)	Difference from Pay Strategy 1	% Change from Pay Strategy 1
SDy = 30%									
Pay Strategy 1	$1,931.43		$1,495.89		$154.67		$280.87	--	--
Pay Strategy 2	$1,940.62		$1,509.66		$142.05		$288.91	$8.04	2.86%
Pay Strategy 3	$1,958.25		$1,492.95		$181.80		$283.50	$2.62	0.91%
SDy = 60%									
Pay Strategy 1	$1,955.02		$1,495.89		$154.67		$304.46	--	--
Pay Strategy 2	$1,973.40		$1,509.66		$142.05		$321.69	$17.22	5.66%
Pay Strategy 3	$2,008.66		$1,492.95		$181.80		$333.91	$29.44	9.15%
SDy = 90%									
Pay Strategy 1	$1,978.61		$1,495.89		$154.67		$328.05	--	--
Pay Strategy 2	$2,006.17		$1,509.66		$142.05		$354.46	$26.41	8.05%
Pay Strategy 3	$2,059.06		$1,492.95		$181.80		$384.31	$56.26	15.87%

These results suggest a different conclusion from the cost analysis presented earlier. Recall that traditional compensation-cost analyses may have led decision makers to the conclusion that a strong link between pay and performance would be unwise given its extreme cost, and that although a moderate pay-for-performance link was not much more expensive than having no link, there were no cost-based data to strongly suggest it as a compelling alternative. When the potential benefits of workforce value are accounted for, however, it becomes clear that investments in performance-based pay may hold the potential for significant organizational improvement. Table 11 indicates that even under our most conservative SDy assumption, pay-for-performance plans yielded greater net values than did the non-contingent pay strategy. That is, by fully incorporating both costs and benefits into our assessment, we find that, under all of our conditions, pay-for-performance is indeed a valuable investment. Moreover, as SDy (i.e., the value associated with performance differences) became larger, the payoff to pay-for-performance increased dramatically, ultimately (i.e., at SDy = 90%) resulting in advantages, relative to the non-contingent pay from pay strategy 1, of over $26 and $56 million dollars for the partially contingent and highly contingent pay strategies, respectively.

Discussion

This analysis suggests that even under conservative assumptions about the value of performance variability among employees, the four-year financial benefit of linking pay to performance in this company would be substantial. When these SDy assumptions are closer to what we believe to be more realistic (i.e., if job performance differences have greater value to an organization), the present model reveals the potentially high payoff from investments in performance-based pay. Moreover, our analysis vividly illustrates the limitations of standard accounting and behavioral cost-based approaches for identifying the critical variables and, thus, the appropriate pay strategy.

Simplifying decisions

Because utility analysis can be rather complex, we used a number of simplifying decisions here. First, we assumed that replacement employees would be of average performance level (and, thus, average service value). This implicitly assumes that pay-for-performance would not influence applicant attraction, even though research suggests that the degree to which pay and performance are linked does in fact matter to applicants (Cable & Judge, 1994). Second, in focusing on the relationship between pay-for-performance and turnover, we made no provisions for whether the performance-based pay would actually improve workforce performance (net of retention effects). This implicit modeling of no effect of performance-based pay on performance is particularly noteworthy given that the contingent pay plan in the Trevor et al. (1997) study was sufficiently well designed to elicit a performance-specific retention pattern. Third, we were working with the relatively normally distributed performance distribution from the Trevor et al. sample. While using this distribution simplified matters by allowing us to make use of other aspects of the Trevor et al. study, we recognize that many performance distributions may be characterized by a greater proportion of employees being rated in the top two or three performance categories and by the subsequent negative skew. The Trevor et al. distribution arose because the organization, consistent with its individualistic and hierarchical culture, encouraged differentiation among employees during performance appraisal. Additionally, because Trevor et al. used averaged performance levels (with a mean of 3.05 performance ratings per employee), such factors as change in performance over time and random error in ratings combined to reduce the likelihood of having an average rating in the very top or bottom performance levels. To the extent that an organization with an aggressive pay-for-performance plan does encourage or mandate a normal performance distribution, however, the implications are noteworthy. For example, the system allocates large raises to the relatively few high performers, who should then be satisfied, motivated, and likely to remain; in contrast, the system also may frustrate, de-motivate, and ultimately result in increased turnover among employees that might be reasonably high performers but were not rated as such as a result of the forced distribution.

We emphasize that each of the three simplifying decisions was made to facilitate our presentation rather than strengthen our results. Indeed, each decision actually weakens the results' apparent support for performance-based pay. In unreported analyses, we incorporated into the utility analysis improved applicant quality under pay strategies 2 and 3, improved performance (net of retention effects) under pay strategies 2 and 3, and a more negative skew in the performance distribution. In each case, these alternative approaches to the decision in question resulted in a larger net advantage for pay strategy 2 and, to an even greater extent, for pay strategy 3. Thus, the analyses we presented here are a simplified and conservative approach. The spreadsheets available from the first author can be adapted to test such alternative assumptions.

On Overcoming the "Futility of Utility"

Our simplifying decisions notwithstanding, the analyses presented here entail much detail and speculation that, according to utility analysis criticism, might hinder their acceptance in managerial ranks. Indeed, we are quite aware of the "futility of utility" (Latham & Whyte, 1997; Whyte & Latham, 1994) findings in which utility analysis appeared to reduce managerial support for an HR intervention. To a large extent, the futility of utility problem likely resides within the presenter and recipients of utility analysis data, rather than with utility analysis itself.

In defense of utility analysis, Sturman (2000) concludes that managers need to understand utility analysis and be trained in the use of the technology. Citing the necessity of managers making decisions based on the Merton and Scholes options pricing formula to have experience in finance and economics, Sturman (2000) argued that "For a complex decision making tool to be useful, the users of the decision aid must desire the information it provides and be trained in its use" (p. 297). Hence, rather than being apologists for the complexity of utility analysis, we believe that in-house I/O psychologists should attempt to convey that it is important for key stakeholders to have some basic grounding in sophisticated human resource decision-making. Given that labor costs often comprise over half of all operating costs (Milkovich & Newman, 2002), training decision makers in a decision tool designed to inform as to the optimal way to allocate these costs would appear to be a valid undertaking. On the presenter side, Cronshaw (1997), after participating as the expert utility presenter in the Whyte and Latham (1997) "futility" study, contended that "it is not utility analysis per se that imperils I/O psychologists, but the intemperate way it is often used. In effect, the messenger kills the message" (p. 614). Cronshaw advocated that utility analysis should be presented as an informational tool rather than as a "persuasive tool in a one-sided (and often self-serving) attempt to 'sell' innovations to managers" (p. 614).

Boudreau and Ramstad (1999; 2002) noted that the powerful influence of disciplines such as Finance and Marketing evolved from their focus on enhancing decisions about the key resource (money or customers), rather than on selling accounting or sales programs, and suggested that the influence of HR and I/O professionals will increase with a similar focus on talent decisions. They suggested (Boudreau & Ramstad, 2002, 2003a; 2003b) the HC BRidge® decision model for "talent" resources that draws upon well-developed decision models to delineate three fundamental elements: efficiency, effectiveness and impact. The present analysis vividly shows the value of integrating "efficiency" (payroll and movement costs); "effectiveness" (changes in movement patterns); and "impact" (value of improvements in performance) into a decision support model, and the dangers of decision frameworks based solely on efficiency or effectiveness alone.

In addition to these emphases on decision maker training and on presenting utility analysis as an informative tool rather than marketing it as a panacea, we also offer a few additional suggestions that might assist the I-O psychologist in communicating utility analyses. First, expectations should be set at the outset by affirming that the evaluation will be somewhat complex, just as would be expected from manufacturing, finance, or accounting. Any simplistic attempt to estimate performance-based pay's effects on the bottom line would be superficial and incomplete. Second, communicating the utility analysis would probably benefit from an initially broad explanation. Perhaps using something similar to our Figure 1 as a guide, the practitioner should emphasize the simple cost-benefit concepts of movement costs, service costs, performance-specific retention, and the critical, but often overlooked, workforce value. We believe that it would be wise to continually hearken back to these big picture concepts, with emphasis on effects rather than on measures (Cascio, 2000) and technical details (Hoffman, 1996). Third, acceptance may be facilitated via emphasis on the conservative nature of the assumptions, decisions, and subsequent estimates (Hoffman, 1996). Finally, highlighting the rationale for these assumptions and decisions should demystify them, and using the spreadsheets to instantaneously show the effects of changing them may provide valuable "best case" and "worse case" scenarios. Together, these recommendations should assist in indicating that well-designed performance-based pay is worth considering, and that HR is able to quantitatively evaluate the relevant alternatives.

Limitations and Conclusions

Several limitations are noteworthy. Our results reflect one organization's characteristics, such as plan specifics, the individual job performance distribution, and the relationship between pay-for-performance and turnover. The extent to which this organization, its employees, and our conclusions are representative of other firms and employees with regard to these factors is unknown. What is critical, however, is that the approach we took to finding these results can be applied in a wide variety of situations, thus enabling the examination of external validity. A second limiting factor in our study is that there may be additional pay strategy-specific training costs or administrative costs that we did not include. We believe, however, that such costs could easily be incorporated into this framework. Third, as discussed throughout this study, we made a number of assumptions and decisions in order to conduct the analyses. Although we believe that we took the most logical and conservative approaches at these junctures, viable arguments could be made for approaches different from our own. Fourth, although we modeled employees' performance levels as stable over time, research has shown that employee performance levels change over time (e.g., Deadrick, Bennett, & Russell, 1997; Ployhart & Hakel, 1998; Sturman & Trevor, 2001). Furthermore, changes in performance levels are related to the likelihood of turnover, even after controlling for the effects of current performance levels (Harrison et al., 1996; Sturman & Trevor, 2001). Considering the movement of employees between different performance categories across years, and the implications of these movements for forecasting turnover, would certainly add complexity to the model we presented. It may be valuable for future research to explore the implications of these model refinements.

The method we describe involves a significant amount of calculation, but is relatively simple to replicate on a spreadsheet. Actual replication may require some customization to fit a specific company's profile, but the basic premise of the methods should be the same. We hope that this demonstration will inspire organizations to more fully tap available research findings to help them enhance their HR policy decision-making. We also hope that this paper helps demonstrate the value of research findings like those reported in Trevor et al. (1997) and will be complemented by future research on additional factors that may influence the pay-for-performance link with turnover. For example, satisfaction with different types of pay-for-performance plans (e.g., raises versus bonuses) can have different effects on outcomes of organizational interest, such as job satisfaction and organizational commitment (Sturman & Short, 2000). Ideally, the research presented here will encourage extensions of this work that can prove valuable for both understanding HR practices in general and for evaluating specific HR policies.

Organizations of all types will likely respond to increasing pressures to "win the talent war" by employing all available tools to enhance attraction, selection, and retention processes. A formidable tool in this endeavor is the accumulated knowledge available from industrial/organizational psychology and human resources research. The method described here illustrates how utility analysis can be used to demystify and integrate this research, making it a more practical decision-making tool, and thus a more potent influence on significant strategic organizational goals (Boudreau, 1991; Boudreau & Ramstad, 1997; 1999; 2002; 2003a; 2003b).

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Footnotes

1. The Boudreau and Berger (1985) model in its purest form would calculate the work force value in each intervening year and apply a discount factor to equalize the time value of the dollar amounts. While these economic corrections can yield substantial changes to the estimated value (Sturman, 2000), such embellishments do not have a significant effect in this case because the changes in dollar amounts are assumed to be linear, the time frame is relatively short, and our focus is on the relative (versus absolute) value of the different strategies. We also did not have information about the organizational tax rate, so we report our results in pre-tax dollars. After-tax effects could be easily calculated by multiplying the final results by an appropriate after-tax proportion, but the relative effects of the options would not be altered.

2. The Bureau of Labor Statistics provides a wealth of information on hourly earnings for diverse groups and occupations (see BLS, 2002). We used the average hourly earnings and weekly hours of all white collar occupations, excluding sales jobs. The most recent information shows that white collar, full-time employees (excluding sales) earned an average hourly wage of $21.65 and worked an average of 39.4 hours per week in 2001. Based on the 29th Annual Report on the 2002-2003 Total Salary Increase Budget Survey (WorldatWork, 2002), salary increases averaged 3.9% for exempt salaried employees in 2002, and is projected to increase 4.1% for 2003. This led us to use an estimated hourly wage of $23.42, for a total salary for 2003 of $47,983. Note again that anyone employing the methods described in this paper can simply enter the data from other sources, such as their own company's data. The value we chose was intended to capture a broad, generalizable sample. More importantly, it is intended to be a reasonable estimate to help illustrate our technique.

3. There is no single accepted method of estimating the dollar value of average performance among workers or applicants. Some research has suggested that average performance value can be estimated equal to the average compensation of the work group (Boudreau, 1991, p. 654; Raju, Burke & Normand, 1990, p. 9). However, it seems unlikely that average-performing employees produce only enough value to offset their direct wage costs. Considering the other service costs that are incurred, and the need for organizations to obtain a positive return on costs, a higher level of average service value seems likely. Based on an analysis of wage and productivity estimates in the national income accounts of the United States, Schmidt and Hunter (1983) proposed assuming that the ratio of average dollar value to average wage is approximately 1.754.

4. Support of the 90% approach is provided by Becker and Huselid (1992), who found direct observations of SDy fell in the 74% to 100% of mean salary range. Moreover, because researchers generally contend that SDy increases as job complexity increases (e.g., Judiesch et al., 1992), our 30% and 60% SDy values would appear to have additional support as conservative estimates, given our sample of all exempt hires in a large company.

Appendix

Computing Separation Probabilities Using Survival Analysis Results

Our estimation uses the survival analysis from Trevor et al.'s (1997) Table 4 (model 1).

Probability of survival = $S(0)^{e^{(ßX)}}$,
where S(0) = baseline probability of survival, which was 0.77,
ß = a vector of survival analysis regression coefficients,
X = a vector of independent variables,
(ßX) = 4.941 + 0.314 * Salary Growth - 2.541 * Performance + 0.553 * Performance^2 - 0.020 * Performance^3 + 0.007 * Salary Growth^3 - 0.663 * Salary Growth * Performance + 0.071 * Salary Growth * Performance^2

The salary growth data used to estimate the equation above was measured in thousands of dollars. Thus, to use the equation, our example's percentage increases had to be converted to a parallel salary growth measure for each pay strategy and performance level combination. To do so, we determined the average pay growth under each strategy by subtracting 2003 pay from 2007 pay, dividing by 4, and then dividing this amount by 1000.

For example, under strategy 3 and performance level 2.5, the average pay increase was [($54,005 - $47,983) / 4]/1000 = 1.5055. The table below lists the salary growth for each pay strategy and performance level.

Performance Category	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Strategy 1	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375
Strategy 2	2.0375	2.0375	2.0375	2.0375	2.0375	2.5853	3.1485	3.7283	4.3243
Strategy 3	0.000	0.4870	0.9888	1.5055	2.0375	2.5853	3.1485	3.7283	4.3243

Next, we need to estimate separation probability (i.e., 1 - probability of survival): 1 - $S(0)^{e^{(ßX)}}$. For example, for performers rated at 5.0 under Pay Strategy 2, the pay increase of 8% translates to an average dollar increase (in thousands) of 4.3243, which yields a separation probability = 1 - $.77^{e^{(ßX)}}$ = 1 - $.77^{e^{(4.941 - 5.467)}}$ = 1 - $.77^{e^{(-0.526)}}$ = 1 - $.77^{(0.5910)}$ = 1 - 0.86 = 0.14. See Table 2 for separation probabilities at each performance level/pay strategy combination.

The 4.941 constant in the (ßX) calculation resulted from adding the estimated model constant (6.810) from Trevor et al.'s equation to the sum of the model terms that included neither performance nor salary growth (e.g. age, promotions). These terms were evaluated at the means of the respective X variables. As an aside, we advocate centering variables prior to conducting hazard analyses, which causes the model constant and variables set at their means to drop out, thus simplifying the calculation of survival probabilities (Retherford & Choe, 1993; Trevor, 2001). See Trevor (2001) and Morita et al. (1993) for more on computing survival probabilities.