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Jeff DeRouen, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

September 23, 2011

RE: ***In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*** **- Case No. 2011-00162**

Dear Mr. DeRouen:

Pursuant to the Commission's Order dated September 16, 2011 in the above-referenced matter, with this letter Louisville Gas and Electric Company (LG&E) is filing one (1) original in paper format of the attachments to LG&E's response to the Commission Staff's First Information Request, Question Nos. 17(b), 32(h), 32(i) and 53(a) dated July 12, 2011, previously provided in electronic format on July 25, 2011.

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Robert M. Conroy

cc: Parties of Record (w/o attachments)

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND	)
ELECTRIC COMPANY FOR CERTIFICATES	)
OF PUBLIC CONVENIENCE AND NECESSITY	) CASE NO.
AND APPROVAL OF ITS 2011 COMPLIANCE	) 2011-00162
PLAN FOR RECOVERY BY ENVIRONMENTAL	)
SURCHARGE	)

Response to the Commission Staff's First Information Request dated July 12, 2011

One Paper Copy for Question Nos. 17(b) and 32(i)

Filed – September 23, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Information Request Dated July 12, 2011

Case No. 2011-00162

Question No. 17

Witness: Lonnie E. Bellar

Q-17. Refer to the Direct Testimony of Lonnie E. Bellar ("Bellar Testimony") at pages 9-10. In the final order in LG&E's most recent base rate case, at pages 28-33, there is discussion of testimony which supported return on equity ("ROE") estimates over a wide range for LG&E. The Commission found that LG&E's "required ROE for both electric and gas operations falls within a range of 9.75 to 10.75 percent with a midpoint of 10.25 percent." Pursuant to KRS 278.183(2)(b), the Commission must establish a reasonable return on capital expenditures for projects included in an environmental compliance plan.

a. Notwithstanding that the parties to Case No. 2009-00549, with the exception of the Attorney General, signed a settlement agreeing to an ROE of 10.63 percent, explain why a 10.63 percent ROE is appropriate on a going forward basis.

b. Provide all economic analyses performed by or for LG&E that demonstrate a ROE of 10.63 percent is reasonable based on current economic conditions.

c. If it is appropriate for the Commission to consider the 10.63 percent ROE established in LG&E's last rate case, and in the absence of any new testimony addressing the derivation of ROE estimates, explain why it would not be appropriate to consider the return on equity testimony also.

d. Provide all support for the position that the Commission's decision in LG&E's last rate case to accept a 10.63 percent ROE for environmental cost recovery obligates the Commission to now adopt that same ROE for a new environmental compliance plan absent a showing that a 10.63 percent ROE is now reasonable.

A-17. a. The 10.63 percent ROE, as agreed to by the eight signatories to the Stipulation in Case No. 2009-00549, is appropriate and reasonable on a going-forward basis. First, the 10.63 percent not only falls within the ROE for electric operations set forth in the Stipulation (10.25% to 10.75%), but likewise falls within the range set forth in the Commission's Order of July 30, 2010 (9.75% to 10.75%). Second, while the Commission issued independent findings that varied from certain terms in the Stipulation, the Commission approved the provisions in the Stipulation containing the 10.63% ROE for ECR purposes "in their entirety." Moreover, KU currently has a pending rate case in Virginia (PUE-2011-00013) in which it has requested a ROE of 11.0 percent, the midpoint of 10.5% and 11.5%. The requested ROE in that proceeding is reflective of the current economic conditions and provides further evidence that the 10.63 percent ROE remains reasonable.

b. Please see the attached direct testimony of Mr. William E Avera, dated April 1, 2011, referenced in response to KPSC Question No. 17(a) on CD in the folder titled Question 17b.

c. The Commission can consider the ROE testimony from the record in Case No. 2009-00549. Please note that the agreed upon 10.63 percent value remains within the range (9.75% to 10.75%) set forth in the Commission's final Order in that proceeding.

d. The 10.63 percent ROE for environmental cost recovery was first approved by the Commission in its February 5, 2009 Order in Case No. 2008-00252, which was a base rate case. The Commission's Order stated that "[t]ypically, an electric utility with an environmental surcharge approved pursuant to KRS 278.183 uses the ROE from its most recent rate case in the return component of the environmental costs included in its surcharge." The Commission then stated that the 10.63 percent ROE had been agreed to by the parties and approved its use. In LG&E's last base rate case, the signatories to the Stipulation agreed to continue use of the 10.63 percent ROE, despite agreeing upon a separate ROE for electric operations. Similarly, the Commission permitted KU to continue use of the 10.63 ROE for environmental cost recovery, but approved a separate ROE for electric operations. The Stipulation contained the resolution of various other items which at the time represented a balanced resolution of the issues under consideration in that case. In keeping with the Commission's precedent, it is reasonable to allow LG&E to utilize the specific ROE for environmental costs approved in LG&E's last rate case, which is the 10.63 percent requested in this proceeding.

BEFORE THE

STATE CORPORATION COMMISSION OF VIRGINIA

Application of:

KENTUCKY UTILITIES COMPANY	)	
D/B/A/ OLD DOMINION POWER COMPANY	)	
	)	**CASE NO. PUE-2011-00013**
For an Adjustment of Electric Base Rates	)	

DIRECT TESTIMONY OF
WILLIAM E. AVERA

FOR KENTUCKY UTILITIES COMPANY
D/B/A OLD DOMINION POWER COMPANY

FINCAP, Inc.
Financial Concepts and Applications, Inc.
3907 Red River
Austin, Texas 78751

Filed: April 1, 2011

COMMONWEALTH OF VIRGINIA
BEFORE THE
STATE CORPORATION COMMISSION

DIRECT TESTIMONY OFWILLIAM E. AVERA

TABLE OF CONTENTS

Exhibits to Direct Testimony

**DIRECT TESTIMONY OF
WILLIAM E. AVERA
FOR KENTUCKY UTILITIES COMPANY
D/B/A OLD DOMINION POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUE-2011-______**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Virginia State Corporation Commission ("SCC" or the "Commission") my assessment of the fair rate of return on common equity ("ROE") for the jurisdictional electric utility operations of Kentucky Utilities Company d/b/a Old Dominion Power Company ("KU/ODP" or the "Company"). In addition, I also examined the reasonableness of the Company's capital structure, considering both the specific risks faced by the Company and other industry guidelines.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit WEA-1.

Q. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A. I am familiar with the organization, finances, and operations of the Company from my participation in prior proceedings before the SCC, Kentucky Public Service Commission ("KPSC") and the Federal Energy Regulatory Commission ("FERC"). 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 KU/ODP. I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for the Company. 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 KU/ODP, and they form the basis of my analyses and conclusions.

Q. WHAT IS THE PRACTICAL TEST OF THE REASONABLENESS OF THE ROE USED IN SETTING A UTILITY'S 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. I first reviewed the operations and finances of KU/ODP and the general conditions in the electric utility industry and the capital markets. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), and also made reference to expected earned rates of return for utilities. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the specific risks and potential challenges for its jurisdictional electric utility operations in Virginia, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity.

B. Summary of Conclusions

Q. WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR KU/ODP?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend an ROE for KU/ODP from the middle of my 10.5 percent to 11.5 percent reasonable range, or 11.0 percent. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with KU/ODP's jurisdictional utility operations, my analyses focused on a proxy group of other electric utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;

- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the DCF and CAPM methods, as well as the expected earnings approach, to estimate a fair ROE;
- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.3 percent to 11.3 percent range, or 10.5 percent to 11.5 percent after incorporating a minimal adjustment to account for the impact of common equity flotation costs;
- The reasonableness of an 11.0 percent ROE for KU/ODP is also supported by the exposures associated with environmental mandates, the need to consider the expected upward trend in capital costs, and the need to support access to capital; and,
- While the Company is exempt from the provisions of the Virginia Electric Restructuring Act, my recommended ROE range encompasses the benchmark earned rate of return threshold produced using the methodology established by the Code of Virginia, and falls well below the 14.1 percent upper bound implied by this guideline.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR ROE RECOMMENDATION IN THIS CASE?

A. My recommendation was reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity; and,
- Providing KU/ODP with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of KU/ODP. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Operations and Finances of KU/ODP

Q. BRIEFLY DESCRIBE KU/ODP AND ITS ELECTRIC UTILITY OPERATIONS.

A. Along with Louisville Gas and Electric Company ("LGE"), KU/ODP is a wholly owned subsidiary of PPL Corporation ("PPL"), which completed its acquisition of the Company from E.ON AG on November 1, 2010. Headquartered in Lexington, Kentucky, KU/ODP is principally engaged in providing regulated electric utility service. In addition to serving approximately 30,000 Virginia customers in Wise, Lee, Russell, Scott, and Dickinson Counties, KU/ODP provides service to over 514,000 retail customers in central, southeastern, and western Kentucky.[3]

Although KU/ODP and LGE are separate operating subsidiaries, they are operated as a single, fully integrated system. Together, KU/ODP's and LGE's utility facilities include over 7,600 megawatts ("MW") of generating capacity, with coal-fired generating stations accounting for approximately 71 percent of this total and 98 percent of the electricity generated by KU/ODP.[4] In addition to company-owned generation, the Company purchases power under a long-term contract and meets a portion of its energy needs by purchases of additional

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[3] KU/ODP also serves less than ten customers in Tennessee.

[4] KU/ODP's total generating capacity is approximately 4,417 MW. These statistics exclude KU/ODP's and LGE's combined 570 MW interest in Trimble County Unit 2.

supplies in the wholesale electricity markets. KU/ODP's transmission and distribution system includes over 22,000 miles of lines. At year-end 2010, the Company had total assets of $4.9 billion, with total revenues of approximately $1.5 billion. KU/ODP is a member of the Southeastern Electric Reliability Council, Inc. and transmission service is available on the Company's system under its own regional Open Access Transmission Tariff. KU/ODP's retail electric operations are subject to the jurisdiction of the SCC and the KPSC. The FERC regulates the Company's interstate transmission and wholesale operations.

Q. IS KU/ODP SUBJECT TO THE REQUIREMENTS OF THE VIRGINIA ELECTRIC RESTRUCTURING ACT?

A. No. When initially approved in 1999, the Virginia Electric Utility Restructuring Act ("Restructuring Act") gave customers the ability to choose their electric supplier and capped electric rates through December 2010. The Company subsequently received a legislative exemption from the customer choice requirements of this law. The Restructuring Act was subsequently amended to terminate customer choice and re-institute regulation of utility rates. As of January 2009, a hybrid model of regulation is being applied in Virginia, which provides for biennial rate reviews. Because of the Company's original exemption from the requirements of the Restructuring Act, it is not subject to this process. In lieu of submitting an annual information filing, KU/ODP has the option of requesting a change in base rates to recover prudently incurred costs by filing a traditional base rate case, as it has done in this proceeding.

Q. PLEASE DESCRIBE PPL.

A. Headquartered in Allentown, Pennsylvania, PPL owns or controls approximately 19,000 MW of generating capacity in the northeastern, northwestern and southeastern U.S., markets wholesale or retail energy primarily in northeastern and northwestern portions of the U.S., and delivers electricity and natural gas to approximately 5.3 million customers in the U.S. and the United Kingdom. During 2010, PPL's revenues totaled approximately $8.5 billion, with total assets at year-end of $32.8 billion.

Q. WHERE DOES KU/ODP OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN ELECTRIC UTILITY PLANT?

A. As a wholly-owned subsidiary, common equity capital provided by investors is obtained solely from the Company's ultimate parent, whose common stock is publicly traded on the New York Stock Exchange. In addition to capital supplied by PPL, KU/ODP also issues debt securities directly under its own name.

Q. WHAT CREDIT RATINGS ARE ASSIGNED TO KU/ODP?

A. Currently, KU/ODP is assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P").[5] Moody's Investors Service ("Moody's") has assigned the Company an issuer rating of "Baa1" and Fitch Ratings Ltd. ("Fitch") has assigned KU/ODP a "A-" issuer default rating.

B. Risks for KU/ODP

Q. HOW HAVE INVESTORS' RISK PERCEPTIONS FOR THE UTILITY INDUSTRY EVOLVED?

A. Implementation of structural change, along with other factors impacting the economy and the industry, has caused investors to rethink their assessment of the relative risks associated with utilities. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised

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[5] KU/ODP remains on CreditWatch "Negative" by S&P. Standard & Poor's Corporation," Research Update: PPL Corp. Is Lowered To 'BBB' And Placed On CreditWatch Negative After Acquisition Announcement," *RatingsDirect* (Mar. 2, 2011).

perceptions of the risks in the industry and the weakened finances of the utilities themselves. In December 2009, S&P observed with respect to the industry's future that:

> Looming costs associated with environmental compliance, slack demand caused by economic weakness, the potential for permanent demand destruction caused by changes in consumer behavior and closing of manufacturing facilities, and numerous regulatory filings seeking recovery of costs are some of the significant challenges the industry has to deal with.[6]

More recently, Moody's concluded:

> [A] sustained period of sluggish economic growth, characterized by high unemployment, could stress the sector's recovery prospects, financial performance, and credit ratings. The quality of the sector's cash flows are already showing signs of decline, partly because of higher operating costs and investments.[7]

Q. DOES THE COMPANY ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A. Yes. KU/ODP will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund new investment in electric generation, transmission and distribution facilities. Together, construction expenditures at KU/ODP and LGE are anticipated to average approximately $1.0 billion annually over the next three years, with Moody's noting that "[e]volving environmental regulations could substantially increase the level of capital expenditures above the amounts currently expected."[8] In addition, KU/ODP must refinance scheduled maturities of $250 million in

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[6] Standard & Poor's Corporation, "U.S. Regulated Electric Utilities Head Into 2010 With Familiar Concerns," *RatingsDirect* (Dec. 28, 2009).

[7] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[8] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov. 1, 2010).

2015. Support for KU/ODP's financial integrity and flexibility will be instrumental in attracting the capital required to meet these fund needs in an effective manner.

Q. IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING CONCERN FOR INVESTORS?

A. Yes. In recent years utilities and their customers have had to contend with dramatic fluctuations in fuel costs due to ongoing price volatility in the spot markets, and investors recognize the potential for further turmoil in energy markets. In times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity. Coal has historically provided relative stability with respect to fuel costs, but prices experienced significant volatility over the 2007 – 2009 time period. The power industry and its customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.

While current expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. For example, heightened uncertainties in the Middle East have led to sharp increases in petroleum prices, and the potential ramifications of the Japanese nuclear crisis on the future cost and availability of nuclear generation in the U.S. have not been lost on investors. S&P observed that "short-term price volatility from numerous possibilities … is always possible,"[9] while Moody's concluded that utilities remain exposed to fluctuations in energy prices, observing, "This view, that commodity prices

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[9] Standard & Poor's Corporation, "Top 10 Investor Questions: U.S. Regulated Electric Utilities," *RatingsDirect* (Jan. 22, 2010).

remain low, could easily be proved incorrect, due to the evidence of historical volatility."[10]

Q. DON'T THE SCC'S ADJUSTMENT MECHANISMS PROTECT KU/ODP FROM EXPOSURE TO FLUCTUATIONS IN POWER SUPPLY COSTS?

A. To a limited extent, yes. The investment community views KU/ODP's ability to periodically adjust retail rates to accommodate fluctuations in fuel and purchased power as an important source of support for KU/ODP's financial integrity. Nevertheless, investors also recognize that there can be a lag between the time KU/ODP actually incurs the expenditure and when it is recovered from ratepayers. As a result, KU/ODP is not insulated from the need to finance deferred power production and supply costs. Indeed, despite the significant investment of resources to manage fuel procurement, investors are aware that the best that KU/ODP can do is to recover its actual costs. In other words, KU/ODP earns no return on fuel costs and is exposed to disallowances for imprudence in its fuel procurement.

Q. WHAT OTHER FINANCIAL PRESSURES IMPACT INVESTORS' RISK ASSESSMENT OF THE COMPANY?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[11] As Moody's observed:

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[10] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[11] Standard & Poor's Corporation, "Industry Economic And Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).

> [W]e also see the sector's overall business risk and operating risks increasing, owing primarily to rising costs associated with upgrading and expanding the nation's trillion dollar electric infrastructure.[12]

As noted earlier, investors anticipate that KU/ODP will undertake significant electric utility capital expenditures. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on KU/ODP.

Q. ARE ENVIRONMENTAL CONSIDERATIONS ALSO AFFECTING INVESTORS' EVALUATION OF ELECTRIC UTILITIES, INCLUDING KU/ODP?

A. Yes. Although KU/ODP's exposure is moderated through an environmental cost recovery mechanism ("ECR") in Kentucky, utilities are confronting increased environmental pressures that could impose significant uncertainties and costs.[13] Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for electric utilities."[14] While the momentum for carbon emissions legislation has slowed, expectations for eventual regulations continue to pose uncertainty. Fitch recently concluded, "Prospects of costly environmental regulations will create uncertainty for investors in the electricity business in 2011."[15] With respect to KU/ODP, Moody's concluded:

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[12] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

[13] Unlike other utilities operating in Virginia, the Company does not operate under an environmental cost recovery factor.

[14] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).

[15] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010)

> Coal-fired baseload generation provides a competitive cost structure but exposes KU to potential future regulation or policies aimed at reducing coal based emissions.[16]

C. Impact of Capital Market Conditions

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

A. The deep financial and real estate crisis that the country experienced in late 2008, and continuing into 2009 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase.

With respect to utilities specifically, as of December 2010, the Dow Jones Utility Average stock index remained approximately 25 percent below the previous high reached in May 2008. This prolonged sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry is not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to congressional representatives in September 2008 as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify

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[16] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov. 1, 2010).

> sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[17]

Similarly, an October 1, 2008 *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.[18] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions had increased the cost of capital for utilities.[19]

While conditions have improved significantly since the depths of the crisis, investors have nonetheless had to confront ongoing fluctuations in share prices and stress in the credit markets. As the Wall Street Journal noted in February 2010:

> Stocks pulled out of a 167-point hole with a late rally Friday, capping a wild week reminiscent of the most volatile days of the credit crisis. ... It was a return to the unusual relationships, or correlations, seen at major flash points over the past two years when investors fled risky assets and jumped into safe havens. This market behavior, which has reasserted itself repeatedly since the financial crisis began, suggests that investment decisions are still being driven more by government support and liquidity concerns than market fundamentals.[20]

In response to renewed capital market uncertainties initiated by unrest in the Middle East, ongoing concerns over the European sovereign debt crisis, and questions over the sustainability of economic growth, investors have repeatedly

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[17] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

[18] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).

[19] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).

[20] Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010).

fled to the safety of U.S. Treasury bonds, and stock prices have experienced renewed volatility.[21] The dramatic rise in the price of gold and other commodities also attests to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil. With respect to electric utilities, Fitch observed that, "the outlook for the sector would be adversely affected by significantly higher inflation and interest rates."[22] Moody's recently concluded:

> Over the past few months, we have been reminded that global financial markets, which are still receiving extraordinary intervention benefits by sovereign governments, are exposed to turmoil. Access to the capital markets could therefore become intermittent, even for safer, more defensive sectors like the power industry.[23]

Uncertainties surrounding economic and capital market conditions heighten the risks faced by electric utilities, which, as described earlier, face a variety of operating and financial challenges.

Q. HOW DO INTEREST RATES ON LONG-TERM BONDS COMPARE WITH THOSE PROJECTED FOR THE NEXT FEW YEARS?

A. Table WEA-1 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

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[21] The Wall Street Journal recently reported that the Dow Jones Industrial Average experienced its largest drop since August 2010, which marked the fourth triple-digit move in less than two weeks. Tom Lauricella and Jonathan Cheng, "Dow Below 12000 on Mideast Worries – Troubles in Europe and China Add to Jitters," *Wall Street Journal* C1 (March. 11, 2011).

[22] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010).

[23] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

Administration ("EIA"), which is a statistical agency of the U.S. Department of Energy ("DOE"):

TABLE WEA-1
INTEREST RATE TRENDS

	Current (a)	2012	2013	2014	2015
30-Yr. Treasury					
Value Line (b)	4.2%	4.9%	5.2%	5.5%	6.0%
IHS Global Insight (c)	4.2%	3.8%	5.0%	5.1%	6.0%
Blue Chip (d)	4.2%	4.8%	5.2%	5.4%	5.5%
AAA Corporate					
Value Line (b)	4.9%	5.6%	6.0%	6.3%	6.5%
IHS Global Insight (c)	4.9%	4.7%	6.0%	6.2%	6.8%
Blue Chip (d)	4.9%	5.4%	5.8%	6.1%	6.3%
S&P (e)	4.9%	6.5%	7.1%	7.2%	--
AA Utility					
IHS Global Insight (c)	5.1%	5.0%	6.2%	6.4%	7.2%
EIA (f)	5.1%	5.5%	6.4%	7.0%	7.4%

(a) Based on monthly average bond yields for the six-month period Sep. 2010 - Feb. 2011 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases/h15/data.htm.
(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 25, 2011).
(c) IHS Global Insight, *U.S. Economic Outlook* at 19 (September 2010).
(d) *Blue Chip Financial Forecasts,* Vol. 29, No. 12 (Dec. 1, 2010).
(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Warming Up Or Frozen Over?," *RatingsDirect* (Feb. 14, 2011).
(f) Energy Information Administration, *Annual Energy Outlook 2011 Early Release* (Dec. 16, 2010).

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2012-2015 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR KU/ODP?

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time, and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would fluctuate as dramatically as they did. While conditions in the economy and capital markets appear to have stabilized significantly since 2009, investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy. The fact remains that the electric utility industry requires significant new capital investment. Given the importance of reliable electric utility service, it would be unwise to ignore investors' increased sensitivity to risk and future capital market trends in evaluating a fair ROE in this case. Similarly, the Company's capital structure must also preserve the financial flexibility necessary to maintain access to capital even during times of unfavorable market conditions.

III. 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 and CAPM analyses conducted to estimate the cost of common equity for benchmark groups 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. 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. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES 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 generally 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. 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.

Q. DID YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF COMMON EQUITY?

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. Therefore, I applied both the DCF and CAPM methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

B. Comparable Risk Proxy Groups

Q. HOW DID YOU IMPLEMENT THESE QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR KU/ODP?

A. Application of the DCF model and other 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 the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

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

A. In order to reflect the risks and prospects associated with KU/ODP's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies classified by Value Line as electric utilities with: (1) S&P corporate credit ratings of "BBB-" to "BBB+", (2) a Value Line Safety Rank of "2" or "3", (3) a Value Line Financial Strength Rating of "B+" to "A", and (4) a market capitalization of $1.6 billion or greater. In addition, I eliminated four utilities (Allegheny Energy, Inc., FirstEnergy Corp., Northeast Utilities, and Progress Energy, Inc.) that otherwise would have been in the proxy group, but are not appropriate for inclusion because they are currently involved in a major merger or acquisition. These criteria resulted in a proxy group composed of 23 companies, which I will refer to as the "Utility Proxy Group."

Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair ROE is relative risk, not the particular business activity or degree of regulation. With 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 comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy 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.

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

A. Yes. Returns 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."[24] 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.[25]

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.

Q. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY PROXY 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 the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. For example,

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[24] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[25] *Federal Power Comm'n v. Hope Natural Gas Co.* (320 U.S. 391, 1944).

Value Line recently observed that near-term growth rates understate the longer-term expectations for gas utilities:

> Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months. Longer-term, we expect these businesses to rebound. An improved economic environment, coupled with stronger pricing, should boost results across this sector over the coming years.[26]

Because the Non-Utility Proxy 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 PROXY GROUP?

A. My comparable risk proxy group of non-utility firms was composed of those U.S. 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 0.85 or less; and, (5) have investment grade credit ratings from S&P.

Q. DO THESE CRITERIA 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.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors

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[26] The Value Line Investment Survey at 445 (Mar. 12, 2010).

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. Although the credit rating agencies are not immune to criticism, their rankings and analyses are widely cited in the investment community and referenced by investors.[27] Investment restrictions tied to credit ratings continue to influence capital flows, and 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. Finally, Value Line's beta *measures the volatility of a security's* price relative to

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[27] While the ratings agencies were faulted during the financial crisis for failing to adequately assess the risk associated with structured finance products, investors continue to regard corporate credit ratings as a reliable guide to investment risks.

the market as a whole. 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.

Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUPS COMPARE WITH KU/ODP?

A. Table WEA-2 compares the Utility Proxy Group with the Non-Utility Proxy Group and KU/ODP across four key indicators of investment risk. Because the Company does not have publicly traded common stock, the Value Line risk measures shown reflect those published for KU/ODP's parent, PPL:

TABLE WEA-2
COMPARISON OF RISK INDICATORS

	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Utility Group	BBB	3	B++	0.74
Non-Utility Proxy Group	A	1	A+	0.70
KU/ODP	BBB	3	B++	0.70

Q. DOES THIS COMPARISON INDICATE THAT INVESTORS WOULD VIEW THE FIRMS IN YOUR PROXY GROUPS AS RISK-COMPARABLE TO KU/ODP?

A. Yes. As discussed earlier, KU/ODP, like its parent, PPL, is rated "BBB" by S&P, which is identical to the average corporate credit rating for the utilities in the Utility Proxy Group. Similarly, the average Safety Rank and Financial Strength Rating for the Utility Proxy group is the same as that assigned to PPL, while PPL's beta value is only marginally lower than the average for the proxy group of other utilities. Considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, and exposure to company specific factors, indicates that investors would likely conclude that the overall investment risks for KU/ODP are comparable to those of the firms in the Utility Proxy Group.

With respect to the Non-Utility Proxy Group, its average credit ratings, Safety Rank, and Financial Strength Rating suggest less risk than for KU/ODP, with its 0.70 average beta indicating identical risk. While the impact of differences in regulation is reflected in objective risk measures, my analyses conservatively focus on a lower-risk group of non-utility firms.

C. 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. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The general form of the DCF model is expressed 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.

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:[28]

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

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

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

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

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

[28] 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.

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 KU/ODP, 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, and more controversial, 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 UTILITY PROXY GROUP DETERMINED?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the utility proxy group are presented on Exhibit WEA-2. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 3.0 percent to 5.6 percent.

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 growth in dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry or 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. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this 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 from approximately 80 percent historically to on the order of 60 percent.[29] 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, 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. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess

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[29] The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 4, 2011 at 2237).

> management, and a crystal ball in which we try to foretell future performance.[30]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[31]

The fact that investment advisory services focus primarily on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[32] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[33]

In 2007, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market

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[30] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).
[31] The Value Line Investment Survey, *Subscriber's Guide* at 53.
[32] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[33] *Id.* at 88.

prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[34]

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

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on Exhibit WEA-2.[35]

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

A. No. 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.

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[34] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).

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

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 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]. 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.[36]

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

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

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 UTILITY PROXY GROUP?

A. The sustainable, "br+sv" growth rates for each firm in the Utility Proxy Group are summarized on Exhibit WEA-2, with the underlying details being presented on Exhibit WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected 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. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY PROXY 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 Exhibit WEA-2.

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.

Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. 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 senior, long-term debt. Consistent with this principle, the DCF results must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

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

A. As noted earlier, the average S&P corporate credit rating for the Utility proxy Group is "BBB", which is identical to KU/ODP. 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 6.1 percent in February 2011.[37] It is inconceivable that investors are not requiring a

[37] Moody's Investors Service, www.credittrends.com.

substantially higher rate of return for holding common stock. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

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. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[38]

Similarly, in its August 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[39]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[40]

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[38] *Southern California Edison Company*, 92 FERC ¶ 61,070 at p. 22 (2000).

[39] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).

[40] *Id.*

The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[41] 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."[42]

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 recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 7.13 percent over the period 2012-2015:

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[41] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[42] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

TABLE WEA-3
IMPLIED BBB BOND YIELD

	2012-15
Projected AA Utility Yield	
IHS Global Insight (a)	6.20%
EIA (b)	6.58%
Average	6.39%
Current BBB - AA Yield Spread (c)	0.74%
Implied Triple-B Utility Yield	**7.13%**

(a) IHS Global Insight, *U.S. Economic Outlook* at 19 (September 2010).

(b) Energy Information Administration, *Annual Energy Outlook 2010* at Table 20 (May 11, 2010).

(c) Based on monthly average bond yields for the six-month period September 2010 - February 2011.

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 more than 100 basis points through the period 2012-2016.[43]

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

A. As shown on Exhibit WEA-2, fifteen low-end DCF estimates ranged from 2.5 percent to 6.9 percent. Nine of these values were below current utility bond yields, with cost of equity estimates below 7.0 percent being less than the yield on triple-B utility bonds expected during the period 2012-2015. In light of the risk-return tradeoff principle and the test applied in *SoCal Edison*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding

[43] *Blue Chip Financial Forecasts*, Vol. 29, No. 12 (Dec. 1, 2010) & Vol. 30, No. 3 (Mar. 1, 2011).

common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC and 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 ANY JUSTIFICATION TO ELIMINATE HIGH-END DCF VALUES FOR THE UTILITY PROXY GROUP?

A. No. As shown on Exhibit WEA-2, the upper end of the cost of equity range produced by the DCF analysis for the firms in the Utility Proxy Group is represented by three values ranging from 15.9 percent to 16.6 percent. While these cost of equity estimates may exceed expectations for most electric utilities, the seven remaining low-end estimates that fall below 8.0 percent 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. In addition, these high-end values fall below the threshold for high-end outliers repeatedly adopted by FERC, which has determined that DCF cost of equity estimates above 17.7 percent are "extreme," and that including such results would "skew the results."[44]

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

A. As shown on Exhibit WEA-2 and summarized in Table WEA-4, below, after eliminating illogical values, application of the constant growth DCF model resulted in average cost of common equity estimates ranging from 9.5 percent to 10.9 percent:

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[44] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004). FERC has continued to utilize this benchmark in evaluating DCF estimates at the upper end of the range. *See, e.g.*, *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 57 (2010).

TABLE WEA-4
DCF RESULTS – UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	10.9%
IBES	10.5%
Zacks	10.8%
br+sv	9.5%

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

A. The results of my constant growth DCF analysis for the Non-Utility Proxy Group, which mirror those for the proxy group of utilities, are presented in Exhibit WEA-4, with the br+sv" growth rates for each firm being presented on Exhibit WEA-5. I noted earlier that values that are implausibly low or high should be eliminated when evaluating the results of any quantitative method used to estimate the cost of equity. As highlighted on Exhibit WEA-4, in addition to illogical low-end values, various DCF estimates for the firms in the Non-Utility Proxy Group exceeded 17.0 percent. I determined that, when compared with the balance of the remaining estimates, these values could be considered implausible and should be excluded.

As shown on Exhibit WEA-4 and summarized in Table WEA-5, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates on the order of at least 12 percent:

TABLE WEA-5
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.9%
IBES	12.4%
Zacks	12.5%
br+sv	12.1%

As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles. My DCF analyses focused on a select group of 50 low-risk firms in the economy – most of which are household names familiar to investors. 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. DO THE HIGHER DCF ESTIMATES FOR THE NON-UTILITY PROXY GROUP DEMONSTRATE THAT THE RISKS OF THESE COMPANIES ARE GREATER THAN KU/ODP?

A. No. While we are accustomed to associating higher risk with higher ROE, DCF estimates of investors' required rate of return do not always produce that result. Performing the DCF calculations for the Non-Utility Proxy Group produced ROE estimates that are higher than the DCF estimates for the Utility Proxy Group, even though the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and Beta – are lower than the risks investors associate with the Utility Proxy Group. The actual cost of equity is unobservable, and DCF estimates may depart from these values because investors' expectations may not be captured by the inputs to the ROE model, particularly the assumed growth rate. Nevertheless, regulators have relied upon DCF calculations for years in evaluating a fair ROE.

The divergence between the DCF estimates for the Utility and Non-Utility Proxy Groups suggests that both should be considered to ensure a balanced end-result.

D. 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. The CAPM is mathematically expressed as:

$$Rj = Rf + \beta j(Rm - Rf)$$

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

A. Application of the CAPM to the Utility Proxy 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 dividend paying firms in the S&P 500.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-years' growth using the rate discussed subsequently $(1 + g)$ to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the consensus earnings 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 354 individual firms, current estimates imply an average growth rate over the next five years of 10.5 percent. Combining this average growth rate with a year-ahead dividend yield of 2.3 percent results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.8 percent. Subtracting a 4.7 percent risk-free rate based on the average yield on 30-year Treasury bonds produced a market equity risk premium of 8.1 percent.

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

A. 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. 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.[45]

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

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.[46]

Because empirical 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 equity.[47] Accordingly, my CAPM analyses incorporated an adjustment to

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

[46] *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at p. 85 (footnote omitted).

[47] *Id.* at Table C-1.

recognize the impact of size distinctions, as measured by the average market capitalization for the respective proxy groups.

Q. WHAT COST OF EQUITY ESTIMATE WAS INDICATED FOR THE UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. The average market capitalization of the Utility Proxy Group is $8.5 billion. Based on data from *Morningstar*, this means that the theoretical CAPM cost of equity estimate must be increased by 74 basis points to account for the industry group's relative size. As shown on Exhibit WEA-6, adjusting the theoretical CAPM result to incorporate this size adjustment results in an average indicated cost of common equity of 11.4 percent.

Q. WHAT COST OF COMMON EQUITY WAS INDICATED FOR THE NON-UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. As shown on Exhibit WEA-7, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 10.0 percent.

Q. SHOULD THE CAPM APPROACH BE APPLIED USING HISTORICAL RATES OF RETURN?

A. No. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased.

Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely than it is today. This incongruity between investors' current expectations and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.[48]

E. 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.

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[48] FERC has previously rejected CAPM methodologies based on historical data because whatever historical relationships existed between debt and equity securities may no longer hold. *See Orange & Rockland Utils., Inc., 40 F.E.R.C. P63,053, at pp. 65,208 -09 (1987), aff'd, Opinion No. 314, 44 F.E.R.C. P61,253 at 65,208.*

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 and the requirements of the Restructuring Act, which specifies a methodology to determine an ROE benchmark based on earned rates of return for a peer group of other regional utilities.[49]

Q. HOW IS THE COMPARISON OF OPPORTUNITY COSTS 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

[49] Code of Virginia at § 56-585.1.A.2.a. As noted earlier, KU is exempt from the requirements of the Restructuring Act.

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 – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost 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 ELECTRIC UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5 percent in 2011 and over its 2013-2015 forecast horizon.[50] Meanwhile, for the firms in the Utility Proxy Group specifically, the returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit WEA-8. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were

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[50] The Value Line Investment Survey at 139 (Feb. 25, 2011).

converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit WEA-3. As shown on Exhibit WEA-8, Value Line's projections for the Utility Proxy Group suggest an average ROE of 10.9 percent.

F. Flotation Costs

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

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

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

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

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

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *New Regulatory Finance* 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.[51]

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%,[52] with PPL incurring issuance costs equal to approximately

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[51] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

[52] *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%.

3.02 percent of the gross proceeds from its 2010 public offering of common stock.[53]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to a representative dividend yield for the Utility Proxy Group of 5 percent implies a flotation cost adjustment on the order of 15 to 50 basis points.

IV. RETURN ON EQUITY FOR KU/ODP

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In addition to presenting my conclusions regarding a fair ROE for KU/ODP, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of the Company's requested capital structure.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW KU/ODP AN ADEQUATE ROE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While KU/ODP remains committed to providing reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with ongoing capital expenditure requirements, uncertain economic and financial market conditions, uncertain environmental

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[53] PPL Corporation, *Prospectus Supplement (To Prospectus dated March 25, 2009)* (Jun. 24, 2010). Net proceeds from PPL's sale of 103.5 million shares of common stock raised approximately $2.41 billion of additional equity capital.

compliance costs, and the potential for continued energy price volatility. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on the Company and its parent, PPL. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These considerations heighten the importance of allowing KU/ODP an adequate ROE.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING THAT KU/ODP HAS ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, the continuation of supportive regulation remains crucial to KU/ODP's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

Fitch concluded, "[G]iven the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects."[54] S&P has also emphasized the need for regulatory support, concluding, "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[55] Similarly, Moody's concluded:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[56]

Q. DOES THE FACT THAT KU/ODP OPERATES UNDER CERTAIN RATE ADJUSTMENT MECHANISMS WARRANT ANY ADJUSTMENT IN THE ESTIMATED LEVEL OF A FAIR ROE?

A. No. Investors recognize that KU/ODP is exposed to significant ongoing risks associated with energy price volatility, rising costs, and uncertainty over the impact of future environmental regulations. Rate adjustment mechanisms are a valuable means of mitigating those risks, but they do not eliminate them. For example, despite the fact that KU/ODP is able to recover incremental environmental costs through the ECR mechanism in Kentucky, Moody's cited the potential environmental regulations or policies as a material risk affecting KU/ODP.[57] No such mechanism exists for KU/ODP in Virginia. While adjustment mechanisms may partially attenuate exposure to attrition in an era of rising costs, such mechanisms ultimately serve only to preserve a utility's

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[54] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[55] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

[56] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).

[57] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov. 1, 2010).

opportunity to earn its authorized return, as required by established regulatory standards.

Moreover, adjustment mechanisms and contractual arrangements that enable utilities to implement rate changes to pass-through fluctuations in fuel costs have been widely prevalent in the industry and utilities increasingly benefit from a wide variety of mechanisms designed to mitigate against the risks associated with fluctuations in costs and regulatory lag. While not always directly analogous to the fuel factor mechanism in effect for KU/ODP in Virginia, the objective is similar; namely, to allow the utility an opportunity to earn a fair rate of return and partially attenuate exposure to attrition in an era of rising costs.

Reflective of this industry trend, the companies in the Utility Proxy Group operate under a variety of cost adjustment mechanisms, which range from riders to recover bad debt expense and post-retirement employee benefit costs to revenue decoupling. Moreover, in response to the heightened risk associated with utilities' exposure to the substantial costs associated with new environmental compliance measures, adjustment mechanisms designed to allow for recovery of these costs outside a general rate case have become increasingly prevalent. As a result, the mitigation in risks associated with utilities' ability to attenuate the impact of fluctuations in costs is already reflected in the cost of common equity estimates developed earlier. Similarly, the firms in the Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether.

Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. Providing a return on fair value that is both commensurate with those available from investments of corresponding risk and sufficient to maintain the ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* and *Hope* decisions; but it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden of higher capital costs and reduced levels of service when the ability of the utility to attract capital is impaired.

B. Capital Structure

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

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive 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 KU/ODP'S REQUESTED CAPITAL STRUCTURE?

A. The Company's capital structure is presented in the testimony of Dan Arbough. As summarized there, common equity as a percent of the capital sources used to compute the overall rate of return for KU/ODP is approximately 52.9 percent.

Q. HOW CAN THE COMPANY'S REQUESTED CAPITAL STRUCTURE BE EVALUATED?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other electric utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

Q. WHAT WAS THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY PROXY GROUP?

A. As shown on Exhibit WEA-9, for the firms in the Utility Proxy Group, common equity ratios at December 31, 2010 ranged between 40.1 percent and 63.8 percent and averaged 48.7 percent of long-term capital.

Q. WHAT CAPITALIZATION IS REPRESENTATIVE FOR THE UTILITY PROXY GROUP GOING FORWARD?

A. As shown on Exhibit WEA-10, Value Line expects an average common equity ratio for the Utility Proxy Group of 51.1 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 41.0 percent to 67.0 percent.

Q. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER ELECTRIC UTILITY OPERATING COMPANIES?

A. Exhibit WEA-10 displays capital structure data at year-end 2010 for the group of electric utility operating companies owned by the firms in the Utility Proxy Group used to estimate the cost of equity. As shown there, common equity ratios for these electric utilities ranged from 43.1 percent to 61.4 percent, and averaged 51.2 percent.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE UTILITY INDUSTRY HAVE FOR THE CAPITAL STRUCTURE MAINTAINED BY KU/ODP?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating economic and financial market uncertainties, and ongoing regulatory risks. Taken together, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, including times of adverse capital market conditions.

Moody's has repeatedly warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[58] More recently, Moody's concluded:

> From a credit perspective, we believe a strong balance sheet coupled with abundant sources of liquidity represents one of the best defenses against business and operating risk and potential negative ratings actions.[59]

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[58] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[59] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

Similarly, S&P noted that, "we generally consider a debt to capital level of 50% or greater to be aggressive or highly leveraged for utilities."[60] Fitch affirmed that it expects regulated utilities "to extend their conservative balance sheet stance in 2010," and employ "a judicious mix of debt and equity to finance high levels of planned investments."[61]

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating KU/ODP's financial risk. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. In order to offset the resulting debt equivalent, the utility must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels.

These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks,[62] with S&P adjusting KU/ODP's reported debt amounts upward to include debt equivalents associated with leases and power purchase obligations.[63] Unless the Company takes action to offset this additional financial risk by maintaining a higher equity

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[60] Standard & Poor's Corporation, "Ratings Roundup: U.S. Electric Utility Sector Maintained Strong Credit Quality In A Gloomy 2009," *RatingsDirect* (Jan. 26, 2010).

[61] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[62] See, *e.g.*, Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008)

[63] Standard & Poor's Corporation, "Kentucky Utilities Co.," *RatingsDirect* (May 6, 2010).

ratio, the resulting leverage will weaken KU/ODP's creditworthiness and imply greater risk.

Q. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF KU/ODP'S REQUESTED CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that the 52.9 percent common equity ratio requested by KU/ODP represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Although this common equity ratio is somewhat higher than the historical and projected averages maintained by the Utility Proxy Group, it is well within the range of individual results and consistent with the trend towards lower financial leverage expected for the industry.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital under reasonable terms so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. KU/ODP's capital structure reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of the Company's capital structure is reinforced by the ongoing uncertainties associated with the electric power industry and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

C. Return on Equity Range Recommendation

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. Reflecting the fact that investors' required return on equity is unobservable and no single method should be viewed in isolation, I used both the DCF and CAPM methods and referenced expected earned rates of return for utilities. In order to reflect the risks and prospects associated with KU/ODP's utility operations, my analyses focused on a proxy group of other electric utilities. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of low-risk companies in the non-utility sectors of the economy.

The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-6, below:

TABLE WEA-6
SUMMARY OF QUANTITATIVE RESULTS

DCF	**Utility**	**Non-Utility**
Earnings Growth		
Value Line	10.9%	11.9%
IBES	10.5%	12.4%
Zacks	10.8%	12.5%
br + sv	9.5%	12.1%
CAPM	11.4%	10.1%
Expected Earnings		
Value Line 2014-16	10.5%	--
Utility Proxy Group	10.9%	--

Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR ROE FOR KU/ODP?

A. Considering the specific exposures faced by KU/ODP, the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity for the Company is in the 10.3 percent to 11.3 percent range. After incorporating a minimal adjustment for flotation costs of 20 basis points to my "bare bones" cost of equity range, I concluded that my analyses indicate a fair ROE for KU/ODP in the 10.5 percent to 11.5 percent range. In light of capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that the midpoint of this range, or 11.0 percent, represents a fair and reasonable ROE for the Company.

Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting KU/ODP's financial position so that the Company remains prepared to respond to unforeseen events that may materialize in the future. Recent challenges in the economic and financial market environment highlight the imperative of maintaining KU/ODP's financial strength in attracting the capital needed to secure reliable service at a lower cost for customers. The reasonableness of my recommended ROE is reinforced by the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

D. Code of Virginia ROE Benchmark

Q. DOES THE CODE OF VIRGINIA ADDRESS SPECIFIC REQUIREMENTS CONCERNING THE DETERMINATION OF A FAIR ROE FOR JURISDICTIONAL ELECTRIC UTILITIES?

A. Yes. Although KU/ODP is exempt from the requirements of the Restructuring Act, in the context of biennial rate proceedings applicable to electric generation, distribution, and transmission services provided by other jurisdictional utilities, the Code of Virginia at § 56-585.1.A.2.a specifies a methodology to determine an ROE benchmark. That methodology provides that the allowed ROE must be no lower than the average historical earned return on book equity for a peer group of regional utilities; nor can it exceed this peer group threshold by more than 300 basis points. The methodology in the Virginia Code is consistent with the economic rationale underpinning established regulatory standards and my expected earnings approach.

Q. WHAT ROE RANGE IS ESTABLISHED BY THE CODE OF VIRGINIA?

A. The results of applying the requirements of § 56-585.1.A are shown in Exhibit WEA-11. Consistent with the Code, the regional peer group consisted of eleven investor-owned utilities with 1) principal operations conducted in the southeastern U.S.,[64] 2) vertically integrated electric utility operations subject to state jurisdiction, and 3) a Moody's credit rating of "Baa" or higher. In addition, companies that do not file financial information with the Securities and Exchange Commission or are affiliated with KU/ODP were excluded. As shown on Exhibit WEA-11, after removing the two utilities with the lowest reported average

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[64] Pursuant to the Code of Virginia, the southeastern U.S. region is defined as those states east of the Mississippi River in either the states of West Virginia or Kentucky or in those states south of Virginia, excluding the state of Tennessee.

returns, as well as the two utilities with the highest returns, the remaining seven companies of the peer group had an average earned rate of return on common equity over the three years 2008-2010 of 11.1 percent. Adding 300 basis points to this ROE floor implies an upper limit of 14.1 percent.

Q. IS YOUR ROE RECOMMENDATION FOR KU/ODP CONSISTENT WITH THIS BENCHMARK?

A. Yes. My recommended ROE of 11.0 percent falls below the average earned ROE for the seven-company regional peer group of 11.1 percent, and well below the implied ceiling of 14.1 percent.

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING THE IMPLICATIONS OF THIS ROE BENCHMARK?

A. While KU/ODP is exempt from the requirements of the Restructuring Act, including those provisions governing the determination of a fair ROE, the Company nevertheless remains exposed to competition from the regional peer group companies in attracting long-term capital. It is a very simple, conceptual principle that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If KU/ODP's allowed return on the book value of its equity investment falls short of other regional utilities, including Appalachian Power Company and Dominion Virginia Power, the implications are clear --investors will be denied the ability to earn their opportunity cost and KU/ODP's ability to attract capital will be eroded.

Q. PLEASE SUMMARIZE YOUR ROE RECOMMENDATION FOR THE COMPANY IN THIS CASE.

A. Based on my review of the risks specific to KU/ODP and the results of my analyses, I conclude that a fair ROE for KU/ODP falls in the range of 10.5 percent to 11.5 percent. In light of capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that the midpoint of this range, or 11.0 percent, represents a fair and reasonable ROE for the Company. My conclusion is supported by the fact that this ROE falls below the 11.1 percent benchmark implied under the Code of Virginia.

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

A. Yes.

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

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

____
William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of March 2011.

______________________(SEAL)
Notary Public

My Commission Expires:

1/10/2015

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

EXHIBIT WEA-1

QUALIFICATIONS OF WILLIAM E. AVERA

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes my background and experience and contains the details of my 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 Virginia State Corporation Commission ("SCC" or the "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.

WILLIAM E. AVERA

FINCAP, INC.
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Economic and Financial Counsel

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Summary of Qualifications

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

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (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 over 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

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; 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 Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board 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

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)

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"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)

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"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)

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

DCF MODEL

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend Yield			Growth Rates				Cost of Equity Estimates			
	Company	Price	Dividends	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	Alliant Energy	$ 38.74	$ 1.70	4.4%	7.0%	8.0%	5.0%	6.1%	11.4%	12.4%	9.4%	10.5%
2	Ameren Corp.	$ 27.67	$ 1.54	5.6%	-2.5%	-1.7%	-2.0%	2.5%	3.1%	3.9%	3.6%	8.1%
3	American Elec Pwr	$ 35.61	$ 1.84	5.2%	3.0%	3.9%	4.0%	4.8%	8.2%	9.1%	9.2%	9.9%
4	Cleco Corp.	$ 31.64	$ 1.08	3.4%	9.5%	3.0%	7.0%	5.5%	12.9%	6.4%	10.4%	8.9%
5	Constellation Energy	$ 31.09	$ 0.96	3.1%	6.0%	9.9%	9.9%	4.7%	9.1%	13.0%	13.0%	7.8%
6	DTE Energy Co.	$ 46.45	$ 2.30	5.0%	6.5%	5.8%	5.0%	3.9%	11.5%	10.8%	10.0%	8.9%
7	Edison International	$ 36.47	$ 1.29	3.5%	-1.0%	4.1%	5.0%	4.7%	2.5%	7.6%	8.5%	8.3%
8	Entergy Corp.	$ 71.46	$ 3.38	4.7%	2.0%	2.0%	1.5%	4.5%	6.7%	6.7%	6.2%	9.2%
9	Exelon Corp.	$ 41.77	$ 2.10	5.0%	-1.5%	-0.8%	-2.5%	5.8%	3.5%	4.2%	2.5%	10.8%
10	Great Plains Energy	$ 19.70	$ 0.87	4.4%	4.5%	8.9%	9.0%	2.4%	8.9%	13.3%	13.4%	6.9%
11	Hawaiian Elec.	$ 24.30	$ 1.24	5.1%	11.5%	7.0%	8.6%	4.2%	16.6%	12.1%	13.7%	9.3%
12	IDACORP, Inc.	$ 37.97	$ 1.20	3.2%	5.5%	4.7%	4.7%	5.0%	8.7%	7.9%	7.9%	8.1%
13	Integrys Energy Group	$ 49.45	$ 2.72	5.5%	11.0%	7.9%	10.4%	3.2%	16.5%	13.4%	15.9%	8.7%
14	OGE Energy Corp.	$ 47.81	$ 1.50	3.1%	6.5%	7.0%	5.5%	7.6%	9.6%	10.1%	8.6%	10.7%
15	PG&E Corp.	$ 45.21	$ 1.92	4.2%	6.0%	6.5%	7.7%	6.7%	10.2%	10.7%	11.9%	10.9%
16	Pinnacle West Capital	$ 41.39	$ 2.10	5.1%	6.0%	6.4%	5.8%	3.7%	11.1%	11.5%	10.9%	8.7%
17	Portland General Elec.	$ 22.80	$ 1.07	4.7%	3.0%	5.0%	5.2%	3.7%	7.7%	9.7%	9.9%	8.4%
18	PPL Corp.	$ 25.02	$ 1.40	5.6%	4.0%	3.6%	NA	7.2%	9.6%	9.2%	NA	12.8%
19	Pub Sv Enterprise Grp	$ 32.23	$ 1.37	4.3%	2.0%	3.3%	0.5%	6.5%	6.3%	7.6%	4.8%	10.8%
20	SCANA Corp.	$ 40.29	$ 1.94	4.8%	3.0%	4.7%	4.6%	5.0%	7.8%	9.5%	9.4%	9.8%
21	Sempra Energy	$ 53.32	$ 1.92	3.6%	1.0%	5.6%	7.0%	5.7%	4.6%	9.2%	10.6%	9.3%
22	Westar Energy	$ 26.29	$ 1.26	4.8%	8.5%	6.1%	5.3%	4.9%	13.3%	10.9%	10.1%	9.7%
23	Wisconsin Energy	$ 29.36	$ 1.05	3.6%	9.5%	8.5%	8.0%	6.5%	13.1%	12.1%	11.6%	10.1%
	Average (g)								**10.9%**	**10.5%**	**10.8%**	**9.5%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Mar. 4, 2011).
(b) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).
(c) *Thomson ReutersCompany in Context Report* (Mar. 3, 2011).
(d) www.zacks.com (retrieved Mar. 4, 2011).
(e) See Exhibit WEA-3.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

BR + SV GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2014					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Alliant Energy	$3.60	$1.92	$30.60	46.7%	11.8%	1.0246	12.1%	5.6%	0.0147	0.3558	0.52%	**6.1%**
2	Ameren Corp.	$2.50	$1.54	$35.50	38.4%	7.0%	1.0144	7.1%	2.7%	0.0122	(0.1833)	-0.22%	**2.5%**
3	American Elec Pwr	$3.50	$2.00	$34.25	42.9%	10.2%	1.0262	10.5%	4.5%	0.0108	0.2389	0.26%	**4.8%**
4	Cleco Corp.	$2.75	$1.45	$25.75	47.3%	10.7%	1.0412	11.1%	5.3%	0.0178	0.1417	0.25%	**5.5%**
5	Constellation Energy	$3.25	$1.00	$47.75	69.2%	6.8%	1.0250	7.0%	4.8%	0.0083	(0.1938)	-0.16%	**4.7%**
6	DTE Energy Co.	$4.25	$2.60	$45.75	38.8%	9.3%	1.0250	9.5%	3.7%	0.0136	0.1682	0.23%	**3.9%**
7	Edison International	$3.25	$1.40	$40.25	56.9%	8.1%	1.0285	8.3%	4.7%	-	(0.0063)	0.00%	**4.7%**
8	Entergy Corp.	$6.75	$3.60	$59.75	46.7%	11.3%	1.0182	11.5%	5.4%	(0.0266)	0.3361	-0.89%	**4.5%**
9	Exelon Corp.	$3.75	$2.10	$26.00	44.0%	14.4%	1.0204	14.7%	6.5%	(0.0136)	0.5048	-0.69%	**5.8%**
10	Great Plains Energy	$1.75	$1.15	$22.50	34.3%	7.8%	1.0251	8.0%	2.7%	0.0297	(0.0976)	-0.29%	**2.4%**
11	Hawaiian Elec.	$2.00	$1.30	$18.00	35.0%	11.1%	1.0220	11.4%	4.0%	0.0098	0.2653	0.26%	**4.2%**
12	IDACORP, Inc.	$3.10	$1.40	$36.50	54.8%	8.5%	1.0303	8.8%	4.8%	0.0181	0.0875	0.16%	**5.0%**
13	Integrys Energy Group	$4.00	$2.72	$41.75	32.0%	9.6%	1.0134	9.7%	3.1%	0.0074	0.1211	0.09%	**3.2%**
14	OGE Energy Corp.	$3.75	$1.65	$30.00	56.0%	12.5%	1.0386	13.0%	7.3%	0.0081	0.3684	0.30%	**7.6%**
15	PG&E Corp.	$4.25	$2.20	$36.25	48.2%	11.7%	1.0384	12.2%	5.9%	0.0332	0.2368	0.79%	**6.7%**
16	Pinnacle West Capital	$3.50	$2.30	$38.25	34.3%	9.2%	1.0339	9.5%	3.2%	0.0418	0.1000	0.42%	**3.7%**
17	Portland General Elec.	$2.00	$1.20	$23.75	40.0%	8.4%	1.0327	8.7%	3.5%	0.0385	0.0500	0.19%	**3.7%**
18	PPL Corp.	$2.75	$1.60	$23.75	41.8%	11.6%	1.0511	12.2%	5.1%	0.0575	0.3667	2.11%	**7.2%**
19	Pub Sv Enterprise Grp	$3.25	$1.50	$27.75	53.8%	11.7%	1.0375	12.2%	6.5%	-	0.3063	0.00%	**6.5%**
20	SCANA Corp.	$3.50	$2.10	$36.75	40.0%	9.5%	1.0420	9.9%	4.0%	0.0470	0.2263	1.06%	**5.0%**
21	Sempra Energy	$4.75	$2.05	$47.50	56.8%	10.0%	1.0230	10.2%	5.8%	(0.0085)	0.1739	-0.15%	**5.7%**
22	Westar Energy	$2.40	$1.40	$24.20	41.7%	9.9%	1.0281	10.2%	4.2%	0.0322	0.1933	0.62%	**4.9%**
23	Wisconsin Energy	$5.25	$2.70	$40.00	48.6%	13.1%	1.0277	13.5%	6.6%	(0.0000)	0.5000	0.00%	**6.5%**

UTILITY PROXY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2009			2014			Chg	2014 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2009	2014	Growth
1	Alliant Energy	51.2%	$5,423	$2,777	51.5%	$6,895	$3,551	5.0%	$55.00	$40.00	$47.50	1.552	110.66	116.00	0.95%
2	Ameren Corp.	49.1%	$15,991	$7,852	51.5%	$17,600	$9,064	2.9%	$35.00	$25.00	$30.00	0.845	237.40	255.00	1.44%
3	American Elec Pwr	45.4%	$28,958	$13,147	48.0%	$35,600	$17,088	5.4%	$55.00	$35.00	$45.00	1.314	478.05	498.00	0.82%
4	Cleco Corp.	45.8%	$2,436	$1,116	53.5%	$3,150	$1,685	8.6%	$35.00	$25.00	$30.00	1.165	60.26	65.00	1.53%
5	Constellation Energy	62.8%	$12,468	$7,830	67.5%	$14,900	$10,058	5.1%	$50.00	$30.00	$40.00	0.838	199.00	209.00	0.99%
6	DTE Energy Co.	46.0%	$13,648	$6,278	48.0%	$16,800	$8,064	5.1%	$65.00	$45.00	$55.00	1.202	165.40	175.00	1.13%
7	Edison International	46.5%	$21,185	$9,851	45.0%	$29,100	$13,095	5.9%	$50.00	$30.00	$40.00	0.994	325.81	325.81	0.00%
8	Entergy Corp.	43.1%	$19,985	$8,614	41.0%	$25,200	$10,332	3.7%	$105.00	$75.00	$90.00	1.506	189.12	173.00	-1.77%
9	Exelon Corp.	52.9%	$25,651	$13,569	53.5%	$31,100	$16,639	4.2%	$60.00	$45.00	$52.50	2.019	662.00	640.00	-0.67%
10	Great Plains Energy	46.2%	$6,045	$2,793	46.0%	$7,800	$3,588	5.1%	$25.00	$16.00	$20.50	0.911	135.42	159.00	3.26%
11	Hawaiian Elec.	50.7%	$2,841	$1,440	52.0%	$3,450	$1,794	4.5%	$30.00	$19.00	$24.50	1.361	95.52	99.00	0.72%
12	IDACORP, Inc.	49.8%	$2,807	$1,398	50.5%	$3,750	$1,894	6.3%	$50.00	$30.00	$40.00	1.096	47.90	52.00	1.66%
13	Integrys Energy Group	53.9%	$5,304	$2,859	52.5%	$6,225	$3,268	2.7%	$55.00	$40.00	$47.50	1.138	75.98	78.50	0.65%
14	OGE Energy Corp.	49.4%	$4,130	$2,040	49.0%	$6,125	$3,001	8.0%	$55.00	$40.00	$47.50	1.583	97.00	99.50	0.51%
15	PG&E Corp.	47.4%	$21,793	$10,330	54.0%	$28,100	$15,174	8.0%	$55.00	$40.00	$47.50	1.310	370.60	420.00	2.53%
16	Pinnacle West Capital	49.6%	$6,687	$3,317	53.5%	$8,700	$4,655	7.0%	$50.00	$35.00	$42.50	1.111	101.43	122.00	3.76%
17	Portland General Elec.	49.7%	$3,100	$1,541	50.0%	$4,275	$2,138	6.8%	$30.00	$20.00	$25.00	1.053	75.21	90.00	3.66%
18	PPL Corp.	40.0%	$20,620	$8,248	51.5%	$26,700	$13,751	10.8%	$45.00	$30.00	$37.50	1.579	485.00	580.00	3.64%
19	Pub Sv Enterprise Grp	60.5%	$15,950	$9,650	58.5%	$24,000	$14,040	7.8%	$45.00	$35.00	$40.00	1.441	506.00	506.00	0.00%
20	SCANA Corp.	47.1%	$7,854	$3,699	49.5%	$11,375	$5,631	8.8%	$55.00	$40.00	$47.50	1.293	128.00	153.00	3.63%
21	Sempra Energy	54.1%	$16,646	$9,005	51.5%	$22,000	$11,330	4.7%	$65.00	$50.00	$57.50	1.211	246.50	238.00	-0.70%
22	Westar Energy	47.4%	$4,778	$2,265	46.0%	$6,520	$2,999	5.8%	$35.00	$25.00	$30.00	1.240	109.07	124.00	2.60%
23	Wisconsin Energy	47.7%	$7,473	$3,565	49.5%	$9,500	$4,703	5.7%	$90.00	$70.00	$80.00	2.000	116.91	116.90	0.00%

(a) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).
(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 2014 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 2013-15 BVPS.

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(c)	(d)	(e)	(e)	(e)	(e)
		Dividend	Growth Rates				Cost of Equity Estimates			
	Company	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	3M Company	2.39%	7.0%	11.9%	11.3%	12.9%	9.4%	14.3%	13.7%	15.3%
2	Abbott Labs.	3.67%	10.0%	8.9%	9.0%	15.0%	13.7%	12.6%	12.7%	18.7%
3	Alberto-Culver	1.02%	15.0%	9.4%	12.5%	8.4%	16.0%	10.4%	13.5%	9.4%
4	AT&T Inc.	6.09%	5.5%	5.7%	7.0%	5.4%	11.6%	11.8%	13.1%	11.5%
5	Automatic Data Proc.	2.93%	8.0%	10.6%	10.8%	9.5%	10.9%	13.5%	13.7%	12.4%
6	Bard (C.R.)	0.77%	9.5%	10.9%	11.8%	18.1%	10.3%	11.7%	12.6%	18.9%
7	Baxter Int'l Inc.	2.45%	10.0%	9.6%	9.3%	15.5%	12.5%	12.1%	11.8%	17.9%
8	Becton, Dickinson	1.97%	9.5%	9.9%	10.8%	9.0%	11.5%	11.9%	12.8%	11.0%
9	Bristol-Myers Squibb	5.11%	8.5%	1.8%	2.0%	5.7%	13.6%	6.9%	7.1%	10.8%
10	Brown-Forman 'B'	1.90%	7.5%	10.9%	13.0%	10.6%	9.4%	12.8%	14.9%	12.5%
11	Chubb Corp.	2.55%	2.5%	8.7%	9.8%	8.0%	5.1%	11.3%	12.4%	10.5%
12	Church & Dwight	0.97%	12.0%	11.8%	12.0%	10.3%	13.0%	12.8%	13.0%	11.3%
13	Coca-Cola	2.80%	9.5%	8.7%	9.0%	9.9%	12.3%	11.5%	11.8%	12.7%
14	Colgate-Palmolive	2.76%	11.0%	9.3%	9.2%	18.1%	13.8%	12.1%	12.0%	20.8%
15	Commerce Bancshs.	2.22%	7.0%	7.0%	7.0%	7.9%	9.2%	9.2%	9.2%	10.1%
16	ConAgra Foods	3.92%	10.5%	7.7%	8.0%	8.1%	14.4%	11.6%	11.9%	12.0%
17	Costco Wholesale	1.24%	7.5%	13.3%	12.9%	8.2%	8.7%	14.5%	14.1%	9.5%
18	Cullen/Frost Bankers	2.96%	4.5%	8.5%	8.0%	5.7%	7.5%	11.5%	11.0%	8.6%
19	CVS Caremark Corp.	1.42%	9.5%	10.1%	12.0%	7.8%	10.9%	11.5%	13.4%	9.2%
20	Ecolab Inc.	1.41%	12.0%	13.2%	13.2%	19.6%	13.4%	14.6%	14.6%	21.0%
21	Exxon Mobil Corp.	2.26%	6.0%	12.1%	8.4%	13.5%	8.3%	14.4%	10.7%	15.7%
22	Gen'l Mills	3.02%	9.5%	7.7%	8.0%	9.3%	12.5%	10.7%	11.0%	12.3%
23	Heinz (H.J.)	3.85%	6.5%	7.0%	8.0%	13.9%	10.4%	10.9%	11.9%	17.8%
24	Hormel Foods	2.01%	10.5%	10.0%	9.3%	10.7%	12.5%	12.0%	11.3%	12.7%
25	Int'l Business Mach.	1.77%	13.0%	11.5%	9.3%	20.4%	14.8%	13.3%	11.1%	22.2%
26	Johnson & Johnson	3.44%	4.5%	6.0%	5.8%	10.8%	7.9%	9.4%	9.2%	14.2%
27	Kellogg	3.14%	9.5%	8.6%	9.0%	9.7%	12.6%	11.7%	12.1%	12.9%
28	Kimberly-Clark	4.09%	6.5%	7.5%	8.7%	18.6%	10.6%	11.6%	12.8%	22.7%
29	Kraft Foods	3.71%	8.0%	8.4%	8.0%	10.7%	11.7%	12.1%	11.7%	14.4%
30	Lilly (Eli)	5.64%	-2.5%	-6.4%	-5.3%	8.4%	3.1%	-0.8%	0.3%	14.0%
31	Lockheed Martin	3.78%	10.0%	8.1%	6.8%	20.3%	13.8%	11.9%	10.6%	24.1%
32	McCormick & Co.	2.24%	8.5%	9.6%	9.5%	13.3%	10.7%	11.8%	11.7%	15.6%
33	McDonald's Corp.	3.25%	9.5%	9.8%	9.3%	10.7%	12.8%	13.1%	12.6%	13.9%
34	McKesson Corp.	0.98%	10.0%	14.2%	11.0%	11.7%	11.0%	15.2%	12.0%	12.7%
35	Medtronic, Inc.	2.47%	7.5%	8.8%	8.4%	11.7%	10.0%	11.3%	10.9%	14.1%
36	Microsoft Corp.	2.26%	12.5%	11.3%	11.7%	15.3%	14.8%	13.6%	14.0%	17.5%
37	NIKE, Inc. 'B'	1.49%	9.5%	10.9%	12.5%	12.2%	11.0%	12.4%	14.0%	13.7%
38	Northrop Grumman	2.82%	12.5%	11.0%	11.1%	7.9%	15.3%	13.8%	13.9%	10.7%
39	PepsiCo, Inc.	2.91%	11.0%	8.9%	9.5%	14.5%	13.9%	11.8%	12.4%	17.4%
40	Pfizer, Inc.	4.50%	5.0%	2.8%	3.5%	7.0%	9.5%	7.3%	8.0%	11.5%
41	Procter & Gamble	3.01%	8.0%	8.9%	9.2%	7.2%	11.0%	11.9%	12.2%	10.3%
42	Raytheon Co.	3.02%	10.0%	8.0%	10.0%	8.6%	13.0%	11.0%	13.0%	11.6%
43	Stryker Corp.	1.26%	12.5%	10.9%	11.4%	13.6%	13.8%	12.2%	12.7%	14.9%
44	Sysco Corp.	3.47%	8.0%	10.0%	9.7%	14.2%	11.5%	13.5%	13.2%	17.6%
45	TJX Companies	1.28%	13.5%	14.5%	14.4%	11.1%	14.8%	15.8%	15.7%	12.4%
46	United Parcel Serv.	2.59%	9.0%	11.7%	11.5%	17.9%	11.6%	14.3%	14.1%	20.5%
47	Verizon Communic.	5.63%	4.0%	6.2%	14.9%	5.7%	9.6%	11.8%	20.5%	11.3%
48	Walgreen Co.	1.68%	11.5%	13.4%	13.0%	8.4%	13.2%	15.1%	14.7%	10.1%
49	Wal-Mart Stores	2.16%	10.0%	10.7%	11.3%	9.9%	12.2%	12.9%	13.5%	12.1%
50	Waste Management	3.52%	5.5%	9.6%	11.0%	5.2%	9.0%	13.1%	14.5%	8.7%
	Average (f)						11.9%	12.4%	12.5%	12.1%

(a) *www.valueline.com (retrieved Jan. 28, 2011).*
(b) *Thomson Reuters Company in Context Report* (Jan. 28, 2011).
(c) www.zacks.com (retrieved Jan. 31, 2011).
(d) See Exhibit WEA-5.
(e) Sum of dividend yield and respective growth rate.
(f) Excludes highlighted figures.

NON-UTILITY PROXY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		--------- 2014 --------					Adjust.			--------- "sv" Factor --------			
	Company	EPS	DPS	BVPS	b	r	Factor	Adj. r	br	s	v	sv	br + sv
1	3M Company	$7.60	$3.10	$40.05	59.2%	19.0%	1.0818	20.5%	12.2%	0.0106	0.6731	0.71%	**12.9%**
2	Abbott Labs.	$5.70	$2.18	$22.05	61.8%	25.9%	1.0384	26.8%	16.6%	(0.0197)	0.7900	-1.56%	**15.0%**
3	Alberto-Culver	$2.35	$0.55	$17.85	76.6%	13.2%	1.0315	13.6%	10.4%	(0.0330)	0.6033	-1.99%	**8.4%**
4	AT&T Inc.	$3.25	$2.00	$24.05	38.5%	13.5%	1.0327	14.0%	5.4%	(0.0001)	0.4656	-0.01%	**5.4%**
5	Automatic Data Proc.	$3.45	$1.60	$22.95	53.6%	15.0%	1.0786	16.2%	8.7%	0.0111	0.7039	0.78%	**9.5%**
6	Bard (C.R.)	$7.75	$0.85	$31.45	89.0%	24.6%	1.0255	25.3%	22.5%	(0.0564)	0.7754	-4.37%	**18.1%**
7	Baxter Int'l Inc.	$5.85	$1.50	$22.90	74.4%	25.5%	1.0560	27.0%	20.1%	(0.0633)	0.7224	-4.57%	**15.5%**
8	Becton, Dickinson	$7.65	$2.20	$34.10	71.2%	22.4%	1.0306	23.1%	16.5%	(0.1030)	0.7216	-7.43%	**9.0%**
9	Bristol-Myers Squibb	$2.35	$1.54	$11.65	34.5%	20.2%	1.0263	20.7%	7.1%	(0.0212)	0.6671	-1.42%	**5.7%**
10	Brown-Forman 'B'	$4.50	$1.48	$20.40	67.1%	22.1%	1.0372	22.9%	15.4%	(0.0640)	0.7368	-4.71%	**10.6%**
11	Chubb Corp.	$7.00	$1.60	$64.85	77.1%	10.8%	1.0184	11.0%	8.5%	(0.0319)	0.1632	-0.52%	**8.0%**
12	Church & Dwight	$5.80	$1.00	$39.25	82.8%	14.8%	1.0465	15.5%	12.8%	(0.0414)	0.6075	-2.52%	**10.3%**
13	Coca-Cola	$4.95	$2.48	$18.20	49.9%	27.2%	1.0479	28.5%	14.2%	(0.0526)	0.8267	-4.34%	**9.9%**
14	Colgate-Palmolive	$7.20	$3.20	$13.25	55.6%	54.3%	1.0671	58.0%	32.2%	(0.1557)	0.9086	-14.15%	**18.1%**
15	Commerce Bancshs.	$3.35	$1.15	$32.10	65.7%	10.4%	1.0480	10.9%	7.2%	0.0240	0.2867	0.69%	**7.9%**
16	ConAgra Foods	$2.35	$1.00	$15.00	57.4%	15.7%	1.0288	16.1%	9.3%	(0.0217)	0.5385	-1.17%	**8.1%**
17	Costco Wholesale	$4.20	$0.95	$33.50	77.4%	12.5%	1.0315	12.9%	10.0%	(0.0301)	0.5939	-1.79%	**8.2%**
18	Cullen/Frost Bankers	$4.35	$2.10	$44.00	51.7%	9.9%	1.0382	10.3%	5.3%	0.0132	0.2667	0.35%	**5.7%**
19	CVS Caremark Corp.	$4.00	$0.56	$38.15	86.0%	10.5%	1.0268	10.8%	9.3%	(0.0395)	0.3642	-1.44%	**7.8%**
20	Ecolab Inc.	$3.60	$0.85	$14.45	76.4%	24.9%	1.0530	26.2%	20.0%	(0.0056)	0.7592	-0.43%	**19.6%**
21	Exxon Mobil Corp.	$9.35	$2.05	$45.50	78.1%	20.5%	1.0546	21.7%	16.9%	(0.0578)	0.5956	-3.44%	**13.5%**
22	Gen'l Mills	$3.15	$1.36	$11.95	56.8%	26.4%	1.0318	27.2%	15.5%	(0.0809)	0.7610	-6.16%	**9.3%**
23	Heinz (H.J.)	$4.10	$2.32	$14.65	43.4%	28.0%	1.0908	30.5%	13.3%	0.0085	0.7830	0.66%	**13.9%**
24	Hormel Foods	$2.10	$0.70	$13.55	66.7%	15.5%	1.0527	16.3%	10.9%	(0.0025)	0.6387	-0.16%	**10.7%**
25	Int'l Business Mach.	$18.00	$3.60	$48.75	80.0%	36.9%	1.0856	40.1%	32.1%	(0.1501)	0.7759	-11.65%	**20.4%**
26	Johnson & Johnson	$5.85	$2.65	$27.60	54.7%	21.2%	1.0378	22.0%	12.0%	(0.0185)	0.6846	-1.26%	**10.8%**
27	Kellogg	$5.10	$1.88	$9.95	63.1%	51.3%	1.0352	53.1%	33.5%	(0.2690)	0.8829	-23.75%	**9.7%**
28	Kimberly-Clark	$6.25	$2.75	$15.55	56.0%	40.2%	1.0140	40.8%	22.8%	(0.0506)	0.8363	-4.24%	**18.6%**
29	Kraft Foods	$3.00	$1.40	$24.00	53.3%	12.5%	1.0480	13.1%	7.0%	0.0716	0.5200	3.72%	**10.7%**
30	Lilly (Eli)	$3.40	$2.20	$15.60	35.3%	21.8%	1.0636	23.2%	8.2%	0.0032	0.6716	0.21%	**8.4%**
31	Lockheed Martin	$13.25	$3.50	$31.25	73.6%	42.4%	1.0882	46.1%	34.0%	(0.1663)	0.8188	-13.62%	**20.3%**
32	McCormick & Co.	$3.50	$1.36	$18.95	61.1%	18.5%	1.0649	19.7%	12.0%	0.0178	0.7293	1.30%	**13.3%**
33	McDonald's Corp.	$6.05	$3.00	$19.00	50.4%	31.8%	1.0303	32.8%	16.5%	(0.0734)	0.8000	-5.87%	**10.7%**
34	McKesson Corp.	$6.80	$0.72	$46.65	89.4%	14.6%	1.0421	15.2%	13.6%	(0.0380)	0.4957	-1.88%	**11.7%**
35	Medtronic, Inc.	$4.50	$1.18	$25.95	73.8%	17.3%	1.0597	18.4%	13.6%	(0.0326)	0.5848	-1.91%	**11.7%**
36	Microsoft Corp.	$3.35	$0.96	$10.75	71.3%	31.2%	1.0763	33.5%	23.9%	(0.1104)	0.7850	-8.66%	**15.3%**
37	NIKE, Inc. 'B'	$5.65	$1.50	$34.60	73.5%	16.3%	1.0643	17.4%	12.8%	(0.0085)	0.6358	-0.54%	**12.2%**
38	Northrop Grumman	$10.25	$2.50	$68.00	75.6%	15.1%	1.0293	15.5%	11.7%	(0.0783)	0.4868	-3.81%	**7.9%**
39	PepsiCo, Inc.	$6.40	$2.34	$24.00	63.4%	26.7%	1.0724	28.6%	18.1%	(0.0449)	0.8118	-3.64%	**14.5%**
40	Pfizer, Inc.	$2.05	$1.16	$13.00	43.4%	15.8%	1.0154	16.0%	7.0%	-	0.5273	0.00%	**7.0%**
41	Procter & Gamble	$5.25	$2.18	$29.45	58.5%	17.8%	1.0230	18.2%	10.7%	(0.0495)	0.6900	-3.41%	**7.2%**
42	Raytheon Co.	$7.20	$2.00	$38.65	72.2%	18.6%	1.0231	19.1%	13.8%	(0.0870)	0.5932	-5.16%	**8.6%**
43	Stryker Corp.	$5.35	$0.84	$32.75	84.3%	16.3%	1.0660	17.4%	14.7%	(0.0144)	0.7213	-1.04%	**13.6%**
44	Sysco Corp.	$2.75	$1.10	$10.10	60.0%	27.2%	1.0502	28.6%	17.2%	(0.0385)	0.7756	-2.98%	**14.2%**
45	TJX Companies	$4.80	$0.80	$12.75	83.3%	37.6%	1.0374	39.1%	32.5%	(0.2565)	0.8355	-21.43%	**11.1%**
46	United Parcel Serv.	$5.50	$2.20	$19.30	60.0%	28.5%	1.0912	31.1%	18.7%	(0.0090)	0.8245	-0.75%	**17.9%**
47	Verizon Communic.	$3.05	$1.96	$18.95	35.7%	16.1%	1.0250	16.5%	5.9%	(0.0032)	0.6555	-0.21%	**5.7%**
48	Walgreen Co.	$3.65	$1.00	$21.15	72.6%	17.3%	1.0252	17.7%	12.8%	(0.0684)	0.6475	-4.43%	**8.4%**
49	Wal-Mart Stores	$6.05	$1.75	$23.40	71.1%	25.9%	1.0072	26.0%	18.5%	(0.1157)	0.7400	-8.56%	**9.9%**
50	Waste Management	$2.90	$1.60	$15.30	44.8%	19.0%	1.0079	19.1%	8.6%	(0.0515)	0.6600	-3.40%	**5.2%**

NON-UTILITY PROXY GROUP

		(a)	(a)	(f)	(a)	(a)		(g)	(a)	(a)	(f)
		---- Common Equity ----			-------- 2014 Price --------				---- Common Shares ----		
	Company	2009	2014	Chg.	High	Low	Avg.	M/B	2009	2014	Growth
1	3M Company	$12,764	$28,975	17.8%	$135.00	$110.00	$122.50	3.059	710.60	723.00	0.35%
2	Abbott Labs.	$22,856	$33,550	8.0%	$115.00	$95.00	$105.00	4.762	1,551.90	1,520.00	-0.41%
3	Alberto-Culver	$1,197	$1,640	6.5%	$50.00	$40.00	$45.00	2.521	98.26	92.00	-1.31%
4	AT&T Inc.	$102,339	$141,895	6.8%	$50.00	$40.00	$45.00	1.871	5,901.90	5,900.00	-0.01%
5	Automatic Data Proc.	$5,323	$11,700	17.1%	$85.00	$70.00	$77.50	3.377	501.70	510.00	0.33%
6	Bard (C.R.)	$2,194	$2,830	5.2%	$155.00	$125.00	$140.00	4.452	95.92	90.00	-1.27%
7	Baxter Int'l Inc.	$7,191	$12,600	11.9%	$90.00	$75.00	$82.50	3.603	600.97	550.00	-1.76%
8	Becton, Dickinson	$5,143	$6,985	6.3%	$135.00	$110.00	$122.50	3.592	237.08	205.00	-2.87%
9	Bristol-Myers Squibb	$14,785	$19,230	5.4%	$40.00	$30.00	$35.00	3.004	1,709.50	1,650.00	-0.71%
10	Brown-Forman 'B'	$1,895	$2,750	7.7%	$85.00	$70.00	$77.50	3.799	146.96	135.00	-1.68%
11	Chubb Corp.	$15,634	$18,800	3.8%	$85.00	$70.00	$77.50	1.195	332.01	290.00	-2.67%
12	Church & Dwight	$1,602	$2,550	9.7%	$110.00	$90.00	$100.00	2.548	70.55	65.00	-1.63%
13	Coca-Cola	$24,799	$40,035	10.1%	$115.00	$95.00	$105.00	5.769	2,303.00	2,200.00	-0.91%
14	Colgate-Palmolive	$3,116	$6,100	14.4%	$160.00	$130.00	$145.00	10.943	494.17	460.00	-1.42%
15	Commerce Bancshs.	$1,886	$3,050	10.1%	$50.00	$40.00	$45.00	1.402	87.26	95.00	1.71%
16	ConAgra Foods	$4,721	$6,300	5.9%	$35.00	$30.00	$32.50	2.167	441.66	420.00	-1.00%
17	Costco Wholesale	$10,018	$13,725	6.5%	$90.00	$75.00	$82.50	2.463	435.97	410.00	-1.22%
18	Cullen/Frost Bankers	$1,894	$2,775	7.9%	$65.00	$55.00	$60.00	1.364	60.04	63.00	0.97%
19	CVS Caremark Corp.	$35,768	$46,750	5.5%	$65.00	$55.00	$60.00	1.573	1,391.00	1,225.00	-2.51%
20	Ecolab Inc.	$2,001	$3,400	11.2%	$65.00	$55.00	$60.00	4.152	236.60	235.00	-0.14%
21	Exxon Mobil Corp.	$110,569	$191,000	11.6%	$125.00	$100.00	$112.50	2.473	4,727.00	4,200.00	-2.34%
22	Gen'l Mills	$5,175	$7,115	6.6%	$55.00	$45.00	$50.00	4.184	656.00	595.00	-1.93%
23	Heinz (H.J.)	$1,891	$4,700	20.0%	$75.00	$60.00	$67.50	4.608	318.06	321.00	0.18%
24	Hormel Foods	$2,124	$3,600	11.1%	$40.00	$35.00	$37.50	2.768	267.19	266.00	-0.09%
25	Int'l Business Mach.	$22,755	$53,650	18.7%	$240.00	$195.00	$217.50	4.462	1,305.30	1,100.00	-3.36%
26	Johnson & Johnson	$50,588	$73,850	7.9%	$95.00	$80.00	$87.50	3.170	2,754.30	2,675.00	-0.58%
27	Kellogg	$2,272	$3,230	7.3%	$95.00	$75.00	$85.00	8.543	381.38	325.00	-3.15%
28	Kimberly-Clark	$5,406	$6,220	2.8%	$105.00	$85.00	$95.00	6.109	417.00	400.00	-0.83%
29	Kraft Foods	$25,972	$42,000	10.1%	$55.00	$45.00	$50.00	2.083	1,477.90	1,750.00	3.44%
30	Lilly (Eli)	$9,524	$18,000	13.6%	$50.00	$45.00	$47.50	3.045	1,149.00	1,155.00	0.10%
31	Lockheed Martin	$4,129	$10,000	19.4%	$190.00	$155.00	$172.50	5.520	372.90	320.00	-3.01%
32	McCormick & Co.	$1,335	$2,555	13.9%	$75.00	$65.00	$70.00	3.694	131.80	135.00	0.48%
33	McDonald's Corp.	$14,034	$19,000	6.2%	$105.00	$85.00	$95.00	5.000	1,076.70	1,000.00	-1.47%
34	McKesson Corp.	$7,532	$11,480	8.8%	$100.00	$85.00	$92.50	1.983	271.00	246.00	-1.92%
35	Medtronic, Inc.	$14,629	$26,600	12.7%	$70.00	$55.00	$62.50	2.408	1,097.30	1,025.00	-1.35%
36	Microsoft Corp.	$39,558	$85,000	16.5%	$55.00	$45.00	$50.00	4.651	8,908.00	7,900.00	-2.37%
37	NIKE, Inc. 'B'	$8,693	$16,550	13.7%	$105.00	$85.00	$95.00	2.746	485.50	478.00	-0.31%
38	Northrop Grumman	$12,687	$17,000	6.0%	$145.00	$120.00	$132.50	1.949	306.87	250.00	-4.02%
39	PepsiCo, Inc.	$17,442	$36,015	15.6%	$140.00	$115.00	$127.50	5.313	1,565.00	1,500.00	-0.84%
40	Pfizer, Inc.	$90,014	$105,000	3.1%	$30.00	$25.00	$27.50	2.115	8,070.00	8,070.00	0.00%
41	Procter & Gamble	$63,099	$79,455	4.7%	$105.00	$85.00	$95.00	3.226	2,917.00	2,700.00	-1.53%
42	Raytheon Co.	$9,827	$12,375	4.7%	$105.00	$85.00	$95.00	2.458	383.20	320.00	-3.54%
43	Stryker Corp.	$6,595	$12,775	14.1%	$130.00	$105.00	$117.50	3.588	397.90	390.00	-0.40%
44	Sysco Corp.	$3,450	$5,700	10.6%	$50.00	$40.00	$45.00	4.455	590.03	565.00	-0.86%
45	TJX Companies	$2,889	$4,200	7.8%	$85.00	$70.00	$77.50	6.078	409.39	330.00	-4.22%
46	United Parcel Serv.	$7,630	$19,035	20.1%	$120.00	$100.00	$110.00	5.699	992.85	985.00	-0.16%
47	Verizon Communic.	$41,600	$53,439	5.1%	$60.00	$50.00	$55.00	2.902	2,835.70	2,820.00	-0.11%
48	Walgreen Co.	$14,376	$18,500	5.2%	$65.00	$55.00	$60.00	2.837	988.56	875.00	-2.41%
49	Wal-Mart Stores	$70,749	$76,025	1.4%	$100.00	$80.00	$90.00	3.846	3,786.00	3,250.00	-3.01%
50	Waste Management	$6,285	$6,800	1.6%	$50.00	$40.00	$45.00	2.941	486.12	445.00	-1.75%

(a) www.valueline.com (retrieved Jan. 28, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of year-end "r" for 2014 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Five-year rate of change.
(g) Average of High and Low expected market prices divided by 2013-15 BVPS.

CAPITAL ASSET PRICING MODEL

UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.3%	
Growth Rate (b)	10.5%	
Market Return (c)		12.8%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.7%
Market Risk Premium (e)		8.1%
Utility Proxy Group Beta (f)		0.74
Utility Proxy Group Risk Premium (g)		6.0%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.7%
Unadjusted CAPM (h)		10.7%
Size Adjustment (i)		0.7%
Implied Cost of Equity (j)		**11.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 28, 2011).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Feb. 23, 2011).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for February 2011 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4 & Feb. 25, 2011).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at Table C-1 (2010).
(j) (h) + (i).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.3%	
Growth Rate (b)	10.5%	
Market Return (c)		12.8%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.7%
Market Risk Premium (e)		8.1%
Non-Utility Proxy Group Beta (f)		0.71
Utility Proxy Group Risk Premium (g)		5.7%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.7%
Unadjusted CAPM (h)		10.4%
Size Adjustment (i)		-0.4%
Implied Cost of Equity (j)		**10.1%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 28, 2011).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Feb. 23, 2011).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for February 2011 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved Jan. 28, 2011).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at Table C-1 (2010).
(j) (h) + (i).

EXPECTED EARNINGS APPROACH

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	12.0%	1.0246	12.3%
2	Ameren Corp.	7.0%	1.0144	$\boxed{7.1\%}$
3	American Elec Pwr	10.5%	1.0262	10.8%
4	Cleco Corp.	10.5%	1.0412	10.9%
5	Constellation Energy	7.0%	1.0250	$\boxed{7.2\%}$
6	DTE Energy Co.	9.0%	1.0250	9.2%
7	Edison International	8.5%	1.0285	8.7%
8	Entergy Corp.	11.5%	1.0182	11.7%
9	Exelon Corp.	14.0%	1.0204	14.3%
10	Great Plains Energy	7.5%	1.0251	7.7%
11	Hawaiian Elec.	10.5%	1.0220	10.7%
12	IDACORP, Inc.	8.5%	1.0303	8.8%
13	Integrys Energy Group	10.0%	1.0134	10.1%
14	OGE Energy Corp.	12.5%	1.0386	13.0%
15	PG&E Corp.	12.0%	1.0384	12.5%
16	Pinnacle West Capital	8.5%	1.0339	8.8%
17	Portland General Elec.	8.5%	1.0327	8.8%
18	PPL Corp.	11.5%	1.0511	12.1%
19	Pub Sv Enterprise Grp	12.5%	1.0375	13.0%
20	SCANA Corp.	10.0%	1.0420	10.4%
21	Sempra Energy	10.5%	1.0230	10.7%
22	Westar Energy	10.0%	1.0281	10.3%
23	Wisconsin Energy	13.0%	1.0277	13.4%
	Average (d)			**10.9%**

(a) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).

(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit WEA-3.

(c) (a) x (b).

(d) Excludes highlighted figures.

CAPITAL STRUCTURE

UTILITY PROXY GROUP

		At Fiscal Year-End 2010 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	Alliant Energy	46.3%	4.2%	49.5%	45.0%	3.5%	51.5%
2	Ameren Corp.	47.1%	0.0%	52.9%	47.5%	1.0%	51.5%
3	American Elec Pwr	55.1%	0.2%	44.7%	52.0%	0.0%	48.0%
4	Cleco Corp.	51.7%	0.0%	48.2%	46.5%	0.0%	53.5%
5	Constellation Energy	34.7%	1.5%	63.8%	32.0%	1.0%	67.0%
6	DTE Energy Co.	49.9%	2.1%	48.0%	52.0%	0.0%	48.0%
7	Edison International	51.9%	3.8%	44.3%	52.0%	3.0%	45.0%
8	Entergy Corp.	54.8%	1.6%	43.6%	58.0%	1.0%	41.0%
9	Exelon Corp.	47.2%	0.3%	52.4%	45.0%	0.0%	55.0%
10	Great Plains Energy	54.0%	0.6%	45.4%	53.5%	0.5%	46.0%
11	Hawaiian Elec.	47.3%	1.2%	51.5%	47.0%	1.0%	52.0%
12	IDACORP, Inc.	51.2%	0.0%	48.8%	49.5%	0.0%	50.5%
13	Integrys Energy Group	47.6%	0.0%	52.4%	46.5%	1.0%	52.5%
14	OGE Energy Corp.	49.6%	0.0%	50.4%	51.0%	0.0%	49.0%
15	PG&E Corp.	50.4%	1.1%	48.5%	45.0%	1.0%	54.0%
16	Pinnacle West Capital	49.3%	0.0%	50.7%	46.5%	0.0%	53.5%
17	Portland General Elec.	53.1%	0.0%	46.9%	50.0%	0.0%	50.0%
18	PPL Corp.	59.9%	0.0%	40.1%	45.5%	1.0%	53.5%
19	Pub Sv Enterprise Grp	48.1%	0.0%	51.9%	40.0%	0.0%	60.0%
20	SCANA Corp.	54.8%	0.0%	45.2%	52.5%	0.0%	47.5%
21	Sempra Energy	50.2%	0.5%	49.2%	47.5%	1.0%	51.5%
22	Westar Energy	54.3%	0.4%	45.3%	53.5%	0.5%	46.0%
23	Wisconsin Energy	53.5%	0.4%	46.2%	50.5%	0.0%	49.5%
	Average	**50.5%**	**0.8%**	**48.7%**	**48.2%**	**0.7%**	**51.1%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).

CAPITAL STRUCTURE

ELECTRIC UTILITY OPERATING COS.

	Company	Long-term Debt	Preferred Stock	Common Equity
1	Interstate Power & Light	45.4%	6.4%	48.2%
2	Wisconsin Power & Light	43.1%	2.4%	54.5%
3	Ameren Illinois Co.	41.2%	0.0%	58.8%
4	Union Electric Co.	48.8%	0.0%	51.2%
5	AEP Texas Central Co.	55.0%	0.4%	44.6%
6	AEP Texas North Co.	54.6%	0.3%	45.0%
7	Appalachian Power Co.	55.6%	0.3%	44.1%
8	Columbus Southern Power Co.	49.2%	0.0%	50.8%
9	Indiana Michigan Power Co.	54.1%	0.2%	45.7%
10	Kentucky Power Co.	55.8%	0.0%	44.2%
11	Ohio Power Co.	46.1%	0.3%	53.6%
12	Public Service Co. of Oklahoma	53.4%	0.3%	46.3%
13	Southwestern Electric Pwr Co.	51.4%	0.1%	48.4%
14	Cleco Power	53.1%	0.0%	46.9%
	Baltimore Gas & Electric Co.	43.8%	5.7%	50.4%
	Detroit Edison Co.	52.1%	0.0%	47.9%
	Southern California Edison Co.	45.3%	5.5%	49.2%
	Entergy Arkansas Inc.	53.4%	3.6%	43.1%
	Entergy Gulf States Louisiana LLC	51.2%	0.3%	48.5%
	Entergy Louisiana LLC	45.8%	2.5%	51.6%
	Entergy Mississippi Inc.	51.5%	3.1%	45.3%
	Entergy New Orleans Inc.	44.2%	5.2%	50.6%
	Entergy Texas Inc.	50.8%	0.0%	49.2%
	Commonweath Edison Co.	41.3%	1.7%	57.0%
	PECO Energy Co.	41.3%	5.0%	53.6%
	Kansas City Power & Light	47.0%	0.0%	53.0%
	Hawaiian Electric Co.	43.5%	1.4%	55.0%
	Idaho Power Co.	53.4%	0.0%	46.6%
	Upper Penninsula Power Co.	38.6%	0.0%	61.4%
	Wisconsin Public Service Corp.	42.3%	2.5%	55.2%
	Oklahoma Gas & Electric Co.	39.2%	0.0%	60.8%
	Pacific Gas & Electric Co.	49.2%	1.1%	49.7%
15	Arizona Public Service Co.	47.9%	0.0%	52.1%
16	Portland General Elec.	53.1%	0.0%	46.9%
17	PPL Electric Utilities Corp.	43.1%	7.3%	49.6%
18	Louisville Gas & Electric Co.	41.4%	0.0%	58.6%
19	Kentucky Utilities Co.	47.0%	0.0%	53.0%
20	Public Service Electric & Gas Co.	49.7%	0.0%	50.3%
21	South Carolina Electric & Gas	46.3%	0.0%	53.7%
22	San Diego Gas & Electric	51.5%	1.2%	47.4%
23	Kansas Gas & Electric	42.8%	0.0%	57.2%
24	Westar Energy	38.1%	0.6%	61.4%
25	Wisconsin Electric Power Co.	39.2%	0.6%	60.2%
	Average	**47.5%**	**1.4%**	**51.2%**

Source: Company Form 10-K Reports and FERC Form-1 Reports.

VIRGINIA PEER GROUP

RETURN ON EQUITY

3-Year Average Return on Equity

1	Alabama Power Co.	13.29%	Removed - Highest	
2	Mississipi Power Co.	12.79%		
3	Progress Energy Carolinas, Inc.	12.28%		
4	Gulf Power Co.	12.18%	Upper Tier Majority	11.9%
5	Georgia Power Co.	12.00%		
6	Progress Energy Florida, Inc.	11.08%	Average 11.1%	
7	Entergy Mississippi Inc.	10.36%		
8	Florida Power & Light Co.	10.23%	Lower Tier Majority	10.3%
9	Tampa Electric Co.	9.64%		
10	Duke Energy Carolinas LLC	9.55%	Removed - Lowest	
11	South Carolina Electric & Gas Co.	9.35%		

RETURN ON EQUITY

	Peer Group Utilities	Return on Average Equity 2010	2009	2008	3-Year Average
1	Alabama Power Co.	13.3%	13.3%	13.3%	13.3%
2	Duke Energy Carolinas LLC	9.8%	9.0%	9.9%	9.6%
3	Entergy Mississippi Inc.	11.4%	11.0%	8.6%	10.4%
4	Florida Power & Light Co.	10.4%	10.1%	10.3%	10.2%
5	Georgia Power Co.	11.4%	11.0%	13.6%	12.0%
6	Gulf Power Co.	11.7%	12.2%	12.7%	12.2%
7	Mississipi Power Co.	11.5%	13.1%	13.8%	12.8%
8	Progress Energy Carolinas, Inc.	12.20%	11.45%	13.19%	12.3%
9	Progress Energy Florida, Inc.	9.6%	11.7%	12.0%	11.1%
10	South Carolina Electric & Gas Co.	8.8%	9.3%	10.0%	9.4%
11	Tampa Electric Co.	11.4%	9.2%	8.4%	9.6%

RETURN ON EQUITY

Company	2010	2009	2008	2007
Alabama Power Co.				
Earnings Available to Common	$ 707.0	$ 669.5	$ 616.0	
Common Equity - Year End	$ 5,393.0	$ 5,236.5	$ 4,854.3	$ 4,410.7
Common Equity - Average	$ 5,314.7	$ 5,045.4	$ 4,632.5	
Return on Average Common Equity	13.3%	13.3%	13.3%	
Duke Energy Carolinas LLC				
Earnings Available to Common	$ 838.0	$ 702.0	$ 690.0	
Common Equity - Year End	$ 8,916.0	$ 8,271.0	$ 7,316.0	$ 6,633.0
Common Equity - Average	$ 8,593.5	$ 7,793.5	$ 6,974.5	
Return on Average Common Equity	9.8%	9.0%	9.9%	
Entergy Mississippi Inc.				
Earnings Available to Common	$ 80.9	$ 74.8	$ 56.9	
Common Equity - Year End	$ 726.2	$ 688.8	$ 665.3	$ 656.7
Common Equity - Average	$ 707.5	$ 677.0	$ 661.0	
Return on Average Common Equity	11.4%	11.0%	8.6%	
Florida Power & Light Co,				
Earnings Available to Common	$ 945.0	$ 831.0	$ 789.0	
Common Equity - Year End	$ 9,791.0	$ 8,436.0	$ 8,089.0	$ 7,275.0
Common Equity - Average	$ 9,113.5	$ 8,262.5	$ 7,682.0	
Return on Average Common Equity	10.4%	10.1%	10.3%	
Georgia Power Co.				
Earnings Available to Common	$ 950.0	$ 814.0	$ 902.9	
Common Equity - Year End	$ 8,741.0	$ 7,902.9	$ 6,879.2	$ 6,435.4
Common Equity - Average	$ 8,322.0	$ 7,391.1	$ 6,657.3	
Return on Average Common Equity	11.4%	11.0%	13.6%	

RETURN ON EQUITY

Company	2010	2009	2008	2007
Gulf Power Co.				
Earnings Available to Common	$ 121.5	$ 111.2	$ 98.3	
Common Equity - Year End	$ 1,075.0	$ 1,004.3	$ 822.1	$ 731.3
Common Equity - Average	$ 1,039.7	$ 913.2	$ 776.7	
Return on Average Common Equity	11.7%	12.2%	12.7%	
Mississipi Power Co.				
Earnings Available to Common	$ 80.2	$ 85.0	$ 86.0	
Common Equity - Year End	$ 737.4	$ 658.5	$ 636.5	$ 613.8
Common Equity - Average	$ 697.9	$ 647.5	$ 625.1	
Return on Average Common Equity	11.5%	13.1%	13.8%	
Progress Energy Carolinas, Inc.				
Earnings Available to Common	$ 600.0	$ 513.0	$ 531.0	
Common Equity - Year End	$ 5,180.0	$ 4,657.0	$ 4,301.0	$ 3,752.0
Common Equity - Average	$ 4,918.5	$ 4,479.0	$ 4,026.5	
Return on Average Common Equity	12.2%	11.5%	13.2%	
Progress Energy Florida, Inc.				
Earnings Available to Common	$ 451.0	$ 460.0	$ 383.0	
Common Equity - Year End	$ 4,890.0	$ 4,490.0	$ 3,399.0	$ 3,002.0
Common Equity - Average	$ 4,690.0	$ 3,944.5	$ 3,200.5	
Return on Average Common Equity	9.6%	11.7%	12.0%	
South Carolina Electric & Gas Co.				
Earnings Available to Common	$ 290.0	$ 272.0	$ 266.0	
Common Equity - Year End	$ 3,437.0	$ 3,162.0	$ 2,704.0	$ 2,622.0
Common Equity - Average	$ 3,299.5	$ 2,933.0	$ 2,663.0	
Return on Average Common Equity	8.8%	9.3%	10.0%	
Tampa Electric Co.				
Earnings Available to Common	$ 242.9	$ 192.1	$ 162.7	
Common Equity - Year End	$ 2,158.2	$ 2,103.8	$ 2,090.6	$ 1,801.0
Common Equity - Average	$ 2,131.0	$ 2,097.2	$ 1,945.8	
Return on Average Common Equity	11.4%	9.2%	8.4%	

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Information Request Dated July 12, 2011

Case No. 2011-00162

Question No. 32

Witness: John N. Voyles, Jr.

Q-32. Refer to Voyles Testimony. Provide the following information for each unit proposed for the addition of AQC equipment:

a. Year placed in service;

b. The number of normal cycles (stops and starts);

c. The number of emergency trips and starts;

d. Heat rate;

e. Capacity factor;

f. Provide for the last 10 years of major internal and minor outages including the major projects completed during each outage;

g. Provide an outline of the major availability and performance detractors;

h. Provide a condition assessment that includes;

(1) Condition of turbine.

(2) Condition of generator.

(3) Condition of boiler.

(4) Condition of balance of plant equipment.

i. Provide any formal life assessment or extension reports.

A-32. a. The requested information is contained in the table below.

Unit	In-Service Date
Mill Creek 1	08/01/72
Mill Creek 2	07/01/74
Mill Creek 3	08/01/78
Mill Creek 4	09/01/82
Trimble County 1	12/23/90

b. The requested information is contained in the table below.

Actual Unit Starts

Unit	2010
Mill Creek 1	22
Mill Creek 2	20
Mill Creek 3	14
Mill Creek 4	22
Trimble County 1	24

Source: Micro *GADS* NERC data.

c. The requested information is contained in the table below. Please note that emergency starts are not applicable to these coal units.

Actual NERC "U1" *(Immediate)* Forced Outages

Unit	2010
Mill Creek 1	14
Mill Creek 2	8
Mill Creek 3	8
Mill Creek 4	14
Trimble County 1	19

Source: Micro *GADS* NERC data.

d. The requested information is contained in the table below.

Actual NERC Net Heat Rate	
Unit	**2010**
Mill Creek 1	10,684
Mill Creek 2	10,845
Mill Creek 3	10,738
Mill Creek 4	10,518
Trimble County 1	10,695

Source: Micro *GADS* NERC data and station reports.

e. The requested information is contained in the table below.

Actual NERC Net Capacity Factor	
Unit	**2010**
Mill Creek 1	75.69
Mill Creek 2	79.95
Mill Creek 3	84.45
Mill Creek 4	78.90
Trimble County 1	80.82

Source: Micro *GADS* NERC data.

f. In response, please find attached a list of major capital projects performed during an outage in the last ten years. The Company is providing the requested information under a Petition for Confidential Protection being filed with the Commission.

g. The requested information is contained in the table below.

2010 Events > 20,000 MWh by Unit:

Unit Name	Event Type	Event Start	Event End	Event Hours	MWH Lost	Event Cause
MC3	U1	1/17/10 6:46	1/19/10 21:51	63.08	25,044	ECONOMIZER LEAKS
MC3	MO	10/29/10 21:55	11/1/10 2:47	52.87	20,988	WET SCRUBBER/ABSORBER TOWER OR MODULE
MC3	MO	9/3/10 23:58	9/6/10 2:45	50.78	20,161	OTHER INDUCED DRAFT FAN PROBLEMS
MC4	MO	6/29/10 2:05	7/2/10 22:47	92.70	45,608	OTHER EXCITER PROBLEMS
MC4	MO	11/11/10 22:45	11/15/10 9:55	83.17	40,918	AIR HEATER FOULING (REGENERATIVE)
MC4	U1	12/12/10 17:16	12/16/10 4:05	82.82	40,746	FIRST SUPERHEATER LEAKS
MC4	MO	6/4/10 22:56	6/8/10 2:48	75.87	37,326	AIR HEATER (REGENERATIVE)
TC1	U1	1/17/10 11.09	2/3/10 15:32	412.38	212,377	GENERATOR HYDROGEN SEALS
TC1	U2	5/3/10 11:23	5/8/10 7:50	116.45	59,972	FIRST REHEATER LEAKS
TC1	U1	6/18/10 8:51	6/21/10 15:59	79.13	40,754	FIRST REHEATER LEAKS
TC1	MO	10/1/10 23:01	10/4/10 22:00	70.98	36,556	FIRST REHEATER LEAKS
TC1	U1	6/14/10 4:23	6/16/10 7:40	51.28	26,411	FIRST REHEATER LEAKS
TC1	SF	10/4/10 22:00	10/6/10 21:47	47.78	24,608	TURBINE LUBE OIL PUMPS
TC1	U2	2/27/10 18:47	3/1/10 14:15	43.47	22,385	FIRST REHEATER LEAKS
TC1	U3	6/5/10 3:27	6/6/10 20:12	40.75	20,986	SECOND SUPERHEATER LEAKS

h. Please see the attached CD in folder titled Question 32(h).

i. Please see the attached CD in folder titled Question 32(i).

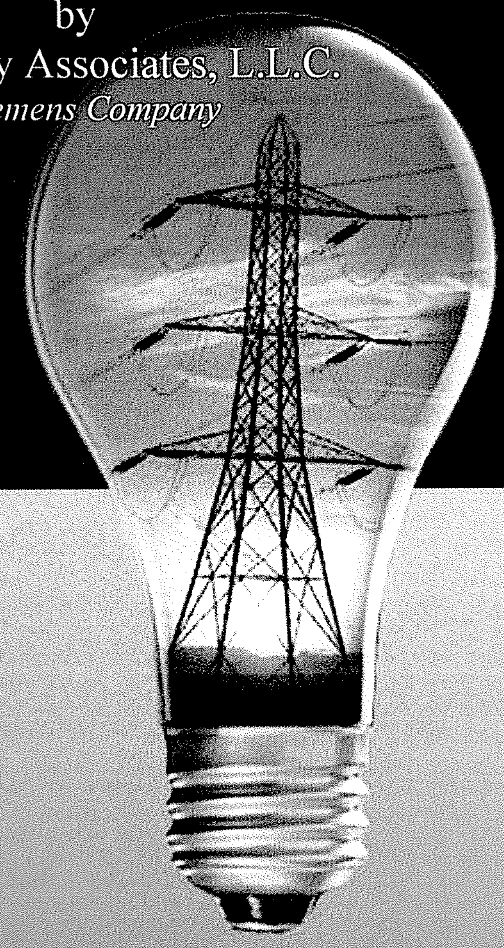
An Economic Life Assessment of Generation Assets of KU and LG&E Performed for

e·on | U.S.

E.ON U.S.

by

NewEnergy Associates, L.L.C.
A Siemens Company



NewEnergy Associates
A Siemens Company

NewEnergy Associates
A Siemens Company

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Table of Contents

A. Introduction:

In order to determine the effective useful economic life of E.ON U.S.'s generating assets, NewEnergy Associates, LLC was retained by E.ON U.S. to perform a Life Assessment of its generating assets. The goal of the analysis was to allow E.ON U.S. to more accurately project when a generating asset will reach the end of its effective useful economic life. With the information supplied by NewEnergy Associates, E.ON U.S. will have a more robust method of determining the depreciation life of an asset. NewEnergy utilized its Strategist strategic planning model, together with E.ON U.S.'s data, to perform this analysis.

B. Methodology:

The analysis was conducted in two phases: an initial phase (Phase 1) to focus on a subset of the generating assets and demonstrate the effectiveness of the proposed methodology, and a second phase (Phase 2) to complete the analysis for the balance of generating assets. The specific tasks for each Phase of the analysis are shown in Appendix A.

For E.ON U.S.'s Life Assessment, units in service for less than 30 years were excluded from the evaluation. None of these units will have been in service for more than 60 years at the end of 2035 and current industry practice indicates that it is both reasonable and cost effective to retain properly operated and maintained units for a life of at least 60 years. The units excluded on the basis of this criterion were the E.W. Brown, Trimble County, Paddys Run 13 combustion turbines, and the Trimble County 1, Ghent 3 & 4, and Mill Creek 3 & 4 coal units.

Figure 1:

Retirement Candidates by Type:

	Net MW	
	Winter 2005	**Summer 2005**
Coal Steam	3,049	3,057
Hydro	56	72
CT	113	99
Total Capacity	**3,218**	**3,228**

Figure 1 shows the total MW of each capacity type of the KU and LG&E assets that were considered for the analysis. Figure 2 shows all KU and LG&E assets and shows the total capacity for those considered in the Life Assessment Analysis. These assets total 3,228 MW (summer). Highlighted assets were not considered in this assessment.

Figure 2:

Kentucky Utilities' Company / Louisville Gas and Electric Company

2006 Generator Ratings (MW)

Plant Name	Owner	In-Service Date	Net Winter 2005	Net Summer 2005	Unit Type	Fuel Type	Age as of December 31, 2006	Age as of December 31, 2035
Brown 1	KU	May 1, 1957	102	101	Steam	Coal	49.67	78.67
Brown 2	KU	June 1, 1963	169	167	Steam	Coal	43.58	72.58
Brown 3	KU	July 1, 1971	433	429	Steam	Coal	35.50	64.50
Total Brown Coal			**704**	**697**				
IAC on 11N2	KU	June 1, 2000		98	Inlet Air Cooling		6.58	35.58
Brown 5	Joint	June 8, 2001	143	117	CT	Natural Gas	5.56	34.56
Brown 6	Joint	August 11, 1999	168	154	CT	Natural Gas/Oil	7.39	36.39
Brown 7	Joint	August 8, 1999	168	154	CT	Natural Gas/Oil	7.40	36.40
Brown 8	KU	February 1, 1995	140	106	CT	Natural Gas/Oil	11.91	40.91
Brown 9	KU	August 1, 1994	140	106	CT	Natural Gas/Oil	12.42	41.42
Brown 10	KU	December 1, 1995	140	106	CT	Natural Gas/Oil	11.08	40.08
Brown 11	KU	May 1, 1996	140	106	CT	Natural Gas/Oil	10.67	39.67
Total Brown CT			**1,039**	**947**				
Cane Run 4	LGE	May 1, 1962	155	155	Steam	Coal	44.67	73.67
Cane Run 5	LGE	May 1, 1966	168	168	Steam	Coal	40.67	69.67
Cane Run 6	LGE	May 1, 1969	240	240	Steam	Coal	37.67	66.67
Total Cane Run			**563**	**563**				
Dix Dam 1	KU	November 1, 1925	8	8	Hydro	Water	81.16	110.16
Dix Dam 2	KU	November 1, 1925	8	8	Hydro	Water	81.16	110.16
Dix Dam 3	KU	November 1, 1925	8	8	Hydro	Water	81.16	110.16
Total Dix Dam			**24**	**24**				
Ghent 1	KU	February 1, 1974	468	475	Steam	Coal	32.91	61.91
Ghent 2	KU	April 1, 1977	466	484	Steam	Coal	29.75	58.75
Ghent 3	KU	May 1, 1981	495	493	Steam	Coal	25.67	54.67
Ghent 4	KU	August 1, 1984	495	493	Steam	Coal	22.41	51.41
Total Ghent			**1,924**	**1,945**				
Green River 3	KU	April 1, 1954	71	68	Steam	Coal	52.75	81.75
Green River 4	KU	July 1, 1959	102	95	Steam	Coal	47.50	76.50
Total Green River			**173**	**163**				
Haefling 1	KU	October 1, 1970	14	12	CT	Natural Gas/Oil	36.25	65.25
Haefling 2	KU	October 1, 1970	14	12	CT	Natural Gas/Oil	36.25	65.25
Haefling 3	KU	October 1, 1970	14	12	CT	Natural Gas/Oil	36.25	65.25
Total Haefling			**42**	**36**				
Mill Creek 1	LGE	August 1, 1972	303	303	Steam	Coal	34.41	63.41
Mill Creek 2	LGE	July 1, 1974	299	301	Steam	Coal	32.50	61.50
Mill Creek 3	LGE	August 1, 1978	397	391	Steam	Coal	28.42	57.42
Mill Creek 4	LGE	September 1, 1982	492	477	Steam	Coal	24.33	53.33
Total Mill Creek			**1,491**	**1,472**				
Ohio Falls 1	LGE	January 1, 1928	4	6	Hydro	Water	79.00	108.00
Ohio Falls 2	LGE	January 1, 1928	4	6	Hydro	Water	79.00	108.00
Ohio Falls 3	LGE	January 1, 1928	4	6	Hydro	Water	79.00	108.00
Ohio Falls 4	LGE	January 1, 1928	4	6	Hydro	Water	79.00	108.00
Ohio Falls 5	LGE	January 1, 1928	4	6	Hydro	Water	79.00	108.00
Ohio Falls 6	LGE	January 1, 1928	4	6	Hydro	Water	79.00	108.00
Ohio Falls 7	LGE	January 1, 1928	4	6	Hydro	Water	79.00	108.00
Ohio Falls 8	LGE	January 1, 1928	4	6	Hydro	Water	79.00	108.00
Total Ohio Falls Hydro			**32**	**48**				
Paddys Run 13	Joint	June 27, 2001	175	158	CT	Natural Gas	5.51	34.51
Total Paddys Run CT			**175**	**158**				
Trimble County 1	LGE	December 23, 1990	386	383	Steam	Coal	16.02	45.02
Total Trimble County			**386**	**383**				
Trimble County 5	Joint	May 14, 2002	180	160	CT	Natural Gas	4.63	33.63
Trimble County 6	Joint	May 14, 2002	180	160	CT	Natural Gas	4.63	33.63
Trimble County 7	Joint	June 1, 2004	180	160	CT	Natural Gas	2.58	31.58
Trimble County 8	Joint	June 1, 2004	180	160	CT	Natural Gas	2.58	31.58
Trimble County 9	Joint	July 1, 2004	180	160	CT	Natural Gas	2.50	31.50
Trimble County 10	Joint	July 1, 2004	180	160	CT	Natural Gas	2.50	31.50
Total Trimble County CT			**1,080**	**960**				
Tyrone 1	KU	October 1, 1947	30	27	CT	Oil	59.25	88.25
Tyrone 2	KU	June 1, 1948	33	31	CT	Oil	58.58	87.58
Tyrone 3	KU	July 1, 1953	73	71	Steam	Coal	53.50	82.50
Total Tyrone			**136**	**129**				
Cane Run 11	LGE	June 1, 1968	14	14	CT	Natural Gas/Oil	38.58	67.58
Paddy's Run 11	LGE	June 1, 1968	13	12	CT	Natural Gas	38.58	67.58
Paddy's Run 12	LGE	July 1, 1968	28	23	CT	Natural Gas	38.50	67.50
Waterside 7	LGE	June 1, 1964	13	11	CT	Natural Gas	42.58	71.58
Waterside 8	LGE	February 1, 1964	13	11	CT	Natural Gas	42.91	71.91
Zorn 1	LGE	May 1, 1969	16	14	CT	Natural Gas	37.67	66.67
Total LG&E CT's			**97**	**85**				
		Total Study Capacity	**3,218**	**3,228**		**Weighted age**	**38**	**67**
							Winter MW	**Summer MW**
(dark shading)	Units that will be less than 60 yrs old in 2035 were not considered in the study						4,559	4,302
(light shading)	Units that were removed from service prior to 2010						89	80

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Phase 1 determined the effective useful economic life of 333 MW (summer net capacity) of the 3,228 MW (summer net capacity) of the life assessment candidates identified in Figure 2. The units designated by E.ON U.S. for evaluation in Phase 1 were: Green River 3 & 4 and Tyrone 3 coal fired steam units, and Haefling, Cane Run 11, Paddy's Run 11 & 12, and Zorn CTs. The CTs were "retired" at the end of 2009 and the coal fired steam units at the end of 2012 for the development of the Phase 1 Life Assessment Reference Plan.

Phase 2 determined the effective useful economic life of the remainder of the 3,228 MW of the life assessment candidates, or 2,895 MW. The effective useful economic lives determined in Phase 1 were incorporated into a newly developed Phase 2 Life Assessment Reference Plan as well as the plans that incorporate each Phase 2 life assessment candidate. All the candidate units included in Phase 2 were either coal fired steam or hydro units, so all of these units were assumed to "retire" at the end of 2012 for the purposes of developing the Phase 2 Life Assessment Reference Plan.

NewEnergy employed a *differential annual revenue requirements* methodology to determine the appropriate effective useful economic life for each unit. The first step involves assuming all the candidate units are "retired" in a specific year. For the life assessment candidates; combustion turbines (CTs) were "retired" at the end of 2009 and the coal and hydro units were "retired" at the end of 2012. These dates were chosen to correspond to the dates when equivalent replacement capacity could be installed. Then, a Reference Plan of replacement capacity was selected by Strategist's PROVIEW resource optimization module. This Reference Plan contains an appropriate mix of peaking, mid-range, and baseload capacity to meet future demand and energy requirements in a least cost method. These capacity types are represented by simple cycle combustion turbines, combined cycle combustion turbines, and coal fired steam generation, respectively.

The alternative resources available for developing the Life Assessment Reference Plans are described briefly in Figure 3. In addition to the annual maximum additions shown for each alternative, these resources were further restricted so that only one large coal unit, of any type, could be added in any one year. This restriction was adopted to limit capital outlay exposure. The only exception to this restriction was for 2013 during the Phase 2 Reference Plan optimization where a large portion of E.ON U.S.'s coal generating assets was "retired" and required more than one coal unit to replace that capacity. In that case, such a limitation would have left the system well below the required minimum reserve margin (see section F; "Results – Phase 2"). Combined Cycle and Simple Cycle Combustion Turbine generators were not limited against the other alternatives. The target minimum reserve margin constraint for the model optimization runs to develop the Life Assessment Reference Plans was set to 2% before 2010, and to 13.71%, 11.75%, and 10.63% for the years 2010, 2011, and 2012 respectively. The minimum target for 2010 through 2012 was adopted to maintain at least the same reserve margin of the base system with no retirements. The low reserve margin target before 2010 reflects an inability to build any new capacity prior to that time. After 2012, the target minimum reserve margin constraint was set to 14%. The 14% reserve margin minimum target from 2013 on reflects the desired long term minimum reserve margin for the system.

Figure 3:

Replacement Capacity Alternatives

Alternative Name	Description	Operating Life	Capacity	Capital Cost	First Year Available	Max per year	Study Period Max
LUSC	Ultra-Super Critical PC	50 years	766 MW	$1,906,270,000	2013	1	10
US_C	Ultra-Super Critical PC with Carbon Sequestration	50 years	613 MW	$2,756,233,000	2013	1	10
IGCC	Integrated Gasification Combined Cycle	50 years	611 MW	$1,758,982,000	2013	1	10
IG_C	Integrated Gasification Combined Cycle with Carbon Sequestration	50 years	488 MW	$2,146,299,000	2013	1	10
LGSC	Super Critical PC	50 years	766 MW	$1,862,896,000	2013	1	10
LG_C	Super Critical PC with Carbon Sequestration	50 years	613 MW	$2,718,858,000	2013	1	10
CCCT	Combined Cycle Combustion Turbine	40 years	552 MW	$465,368,900	2011	1	10
SCCT	Simple Cycle Combustion Turbine	30 years	181 MW	$78,687,500	2010	4	25

Capital Cost Values are shown in 2006$

Once the Reference Plan was developed, the replacement capacity was converted to "deferral capacity". The replacement resources designated as "deferrable" have their capacity adjusted to maintain the same reserve margin as the Reference Plan for all plans with Life Assessment candidate units included. Fixed O&M and capacity costs were also adjusted accordingly. In any year, the last unit added in the Reference Plan is the first one from which capacity is deferred. Due to the relatively high capital costs of the Carbon Sequestration units added in the later years, the Life Assessment candidate units were always less expensive to retain than the replacement carbon sequestration units. Since there were several years of negative PV annual revenue requirements differentials preceding the first of the carbon units, carbon sequestration units were not included in the deferrable capacity.

The basic system modeling was supplemented with specific cost data for each of the candidate units; projecting their O&M costs, capital expenditures (CapEx), property tax and insurance costs, as well as depreciation expenses out to 2035. These are discussed in more detail below. It is widely recognized that operating parameters such as EFOR, maintenance outage requirements, and heat rates increase (degrade) over the lifetime of an asset. Projections of future performance for aging generators would, ideally, be based on such data. However, no reliable source of data to project this performance degradation over the life of an asset currently exists. Thus, NewEnergy instead adopted the assumption that maintenance and capital expenditures would increase over the lifetime of the asset to hold performance at average lifetime levels. Data from OEM sources to support and model this assumption both exists and is readily available.

Fixed O&M costs and total capital costs (represented by the resource's Economic Carrying Charge) of the deferrable resources are also adjusted to reflect their computed capacities. The model is then run to determine the production costs for this adjusted system

The next step develops plans where each of the candidate units is not retired and assumes that each unit will then remain in service for at least 30 years. The Present Value (PV) of the annual revenue requirements is extracted from the model for each plan retaining one of the candidate units. The difference between these PV annual revenue requirements and the PV annual revenue requirements of the Reference Plan is then computed. The first year the difference is negative (the retention costs more than the retirement) is determined and this indicates the earliest potential date for the end of the asset's effective useful economic life. The PV annual revenue requirements differentials are then accumulated from that year forward and the point where the sum turns negative and remains negative is the latest potential date for the end of the asset's effective useful economic life. This is shown in the example in Figure 4; the earliest year that the example unit would reach the end of its effective useful economic life in this case is 2014, with the latest economic retirement in 2018.

A possible situation, which does arise with some Phase 2 units, is that the first negative year for PV annual revenue requirements occurs relatively early, and then several years with positive PV annual revenue requirements follow before the annual PV differential values become negative again. This results in pushing the end of the asset's effective useful economic life out by several years while an accumulated positive differential sum is eliminated by the subsequent accumulation of negative differentials. It is not reasonable to wait until all the benefits accumulated during the intervening positive differential years are eliminated by retaining the unit for several years of negatives. In these cases, it is sensible to ignore the first occurrence of a negative differential, and to wait for the differential series to show stable negatives before beginning the summation.

It is possible for the methodology to indicate *no* end of effective useful economic life for a particular unit in the time frame of the study; in this case through 2035. This means that, based upon the assumptions used, the actual end of the asset's effective useful economic life is beyond 2035.

Figure 4:

Illustration of the Determination of the Effective Useful Economic Life For a Life Assessment Candidate Unit

Year	Differential Annual Revenue Requirements	Cumulative NPV of Differential Annual Revenue Requirements *(2014 and beyond)*
2010	$1.00	
2011	$1.50	
2012	$0.80	
2013	$0.60	
2014	($0.03)	($0.03)
2015	($0.50)	($0.53)
2016	$0.40	($0.13)
2017	$0.30	$0.17
2018	($0.50)	($0.33)
2019	($0.70)	($1.03)
2020	($1.00)	($2.03)
2021	($0.60)	($2.63)
2022	($0.20)	($2.83)
2023	$0.20	($2.63)
2024	$0.50	($2.13)
2025	($0.80)	($2.93)
2026	($0.10)	($3.03)
2027	$0.05	($2.98)
2028	$0.01	($2.97)
2029	($0.40)	($3.37)
2030	($0.10)	($3.47)
2031	($0.50)	($3.97)
2032	$0.30	($3.67)
2033	$0.50	($3.17)
2034	($0.30)	($3.47)
2035	($0.10)	($3.57)

C. Model Data and Assumptions:

E.ON U.S. provided NewEnergy with their latest Strategist database, translated from a PowerBase database. This basic data included all operating parameters and costs for the existing generation units in the KU and LG&E system. This includes EFOR, scheduled outage requirements, heat rates, variable and fixed operating and maintenance costs for all the generating assets, as well as load and fuel cost forecasts over the study horizon (2006 to 2035). A loads and resources summary report from the Strategist model reflecting only the existing system for selected years over the study horizon is shown in Figure 5.

Figure 5:

Loads and Resources 2006 - 2035

	2006	2010	2015	2020	2025	2030	2035
LOADS							
=====							
PEAK BEFORE DSM	6948.3	7434	8023	8597	9142	9735	10313
+ DSM ADJUSTMENTS	-112.3	-162.5	-167.4	-165.4	-141.9	-138.7	-138.7
----------------	-----------	-----------	-----------	-----------	-----------	-----------	-----------
FINAL PEAK	6836	7271.5	7855.6	8431.6	9000.1	9596.3	10174.3
RESOURCES							
=========							
TOTAL HYDRO	59.6	75.5	94.9	94.9	94.9	94.9	94.9
TOTAL THERMAL	7724.9	8099.2	8099.2	8099.2	8099.2	8099.2	8099.2
TOTAL CAPACITY	7784.5	8174.7	8194.1	8194.1	8194.1	8194.1	8194.1
RESERVES							
========							
RESERVE (MW)	948.6	903.2	338.5	-237.5	-806	-1402.2	-1980.2
RESERVE MARGIN PERCENT	13.88	12.42	4.31	-2.82	-8.96	-14.61	-19.46
CAPACITY MARGIN PERCENT	12.19	11.05	4.13	-2.9	-9.84	-17.11	-24.17

Historical O&M costs and capital expenditure streams for individual units are significantly volatile with large expenditures in some years and very little expenditures in others. This creates problems in projecting the forward trajectory for these costs. Furthermore, Capital Expenditures should be amortized over the remaining life of the asset. Some of these Capital Expenditure (CapEx) outlays would also be expected to extend the life of the asset, requiring a rolling realignment of capital depreciation for every year of the asset's remaining life. Strategist is, unfortunately, unable to handle this internally so a complex spreadsheet calculation would be required to determine the proper annual revenue requirements impacts associated with CapEx. This procedure is both unwieldy and error prone; so a simplifying assumption to treat the CapEx outlays as if they were expenses for the "extended" life of the retained assets was made.

Projections of the depreciation streams were also needed. It was assumed that since the candidate resources all are retired at specific times (the end of 2009 for CTs, the end of 2012 for Hydro and Coal Steam units), that any net plant balance at that time would have to be reallocated over the assumed additional 30 year life of the resource if it is retained. The depreciation was calculated using straight line depreciation. The calculation of property tax and insurance costs were determined by E.ON U.S. experts in those areas.

All five of these cost streams (O&M, capital expenditures, depreciation, property taxes, and insurance) were then added together for each year of the "extended life" of the asset and overlaid on the Fixed O&M Cost within the Strategist model's database for each candidate unit.

Finally, the candidate units were overlaid on the Reference Plan one at a time and the Present

Value of each year's revenue requirements (equivalent to the PV Utility Cost model output from PROVIEW) was extracted from the model and the differentials with the Reference Plan calculated.

D. Results – Reference Plan

The Life Assessment Reference Plans developed for Phase 1 and Phase 2 are shown below in Figure 6. Please note that the large number of units added in 2013 for the Phase 2 Reference Plan is the result of "replacing" the large amount of capacity that the candidate units represent. For Phase 2, two units were again needed in 2018 due to capacity that had reached the end of its effective useful economic life as projected from Phase 1. These "retirements" were included in the underlying base data for Phase 2.

Figure 6:

Life Assessment Reference Plans

	Phase 1 Reference Plan	Phase 2 Reference Plan
2006		
2007		
2008		
2009		
2010	SCCT(1)	
2011		SCCT(1)
2012		
2013	LGSC(1)	LGSC(7)
2014	SCCT(1)	
2015	SCCT(1)	SCCT(1)
2016	SCCT(1)	SCCT(1)
2017		SCCT(1)
2018	LG_C(1)	SCCT(2)
2019		SCCT(1)
2020		SCCT(1)
2021		SCCT(1)
2022	LG_C(1)	LG_C(1)
2023		
2024		
2025		
2026	IG_C(1)	IG_C(1)
2027		
2028		
2029	LGSC(1)	
2030		SCCT(1)
2031		IG_C(1)
2032		
2033		
2034		SCCT(1)
2035	LG_C(1)	SCCT(1)
2036		IG_C(1)
P.V. UTILITY COST:		
PLANNING PERIOD	$ 18,235,858	$ 23,785,290
END EFFECTS PERIOD	$ 9,224,502	$ 10,936,946
STUDY PERIOD	$ 27,460,360	$ 34,722,236

E. <u>Results – Phase 1:</u>

The numeric results of Phase 1 are presented in Figures 7 and 8. The end of effective useful economic lives for the coal fired steam generation in Phase 1, Green River 3 & 4 and Tyrone 3, are all 2018. Note that the first year with a negative value for Green River 3 is 2016, but the positive value in 2017 offsets this, as well as the negatives in the next several years, delaying the next accumulated negative until 2021. For this reason the negative value in 2016 is ignored, resulting in a projected end of effective useful economic life for Green River 3 in 2018. None of the peaking turbines show a projected end of effective useful economic life. This is due to the fact that once sufficient new peaking capacity is added, these units generate at very low capacity factors and the overall cost of retaining this capacity is relatively low.

Figure 7:

Phase 1

Present Value Utility Cost Differentials vs. All New Build Plan

(PVUC New Build - PVUC Existing Unit)

	Coal Steam Green River 3	Coal Steam Green River 4	Coal Steam Tyrone 3	Gas CT Cane Run 11	Gas CT Haefling	Gas CT Paddy's Run 11	Gas CT Paddy's Run 12	Gas CT Zorn	All New Build
2006	$0	$0	$0	$0	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$270	$2	$290	($146)	$430	$0
2011	$0	$0	$0	$618	$1,607	$517	$1,080	$628	$0
2012	$0	$0	$0	$611	$1,542	$518	$1,042	$622	$0
2013	$2,556	$3,583	$2,728	$980	$2,472	$838	$1,615	$992	$0
2014	$711	$1,089	$782	$542	$1,367	$463	$925	$555	$0
2015	$738	$961	$853	$480	$1,275	$434	$841	$525	$0
2016	($159)	$802	$619	$480	$1,234	$414	$824	$494	$0
2017	$624	$930	$132	$454	$1,137	$391	$780	$468	$0
2018	($2)	($38)	($49)	$436	$1,078	$379	$741	$451	$0
2019	($60)	($504)	($68)	$392	$980	$339	$662	$406	$0
2020	($322)	($162)	($169)	$347	$934	$322	$619	$386	$0
2021	($265)	($181)	($140)	$344	$869	$300	$602	$359	$0
2022	($460)	($548)	($452)	$325	$819	$283	$565	$339	$0
2023	($889)	($561)	($604)	$305	$779	$266	$531	$319	$0
2024	($485)	($701)	($949)	$281	$726	$244	$495	$295	$0
2025	($511)	($725)	($651)	$244	$652	$229	$446	$276	$0
2026	($491)	($1,081)	($635)	$249	$625	$218	$437	$262	$0
2027	($507)	($767)	($649)	$227	$572	$200	$401	$240	$0
2028	($549)	($827)	($667)	$228	$545	$204	$385	$240	$0
2029	$744	$983	$658	$453	$1,159	$393	$773	$466	$0
2030	$426	$908	$606	$405	$1,083	$363	$707	$431	$0
2031	$535	$689	$221	$383	$971	$333	$652	$394	$0
2032	$459	$590	$377	$346	$891	$301	$597	$357	$0
2033	$262	$85	$174	$300	$755	$262	$513	$310	$0
2034	$237	$287	$151	$277	$706	$242	$478	$287	$0
2035	$616	$813	$550	$336	$881	$302	$579	$357	$0

Figure 8:

Phase 1

Accumulated PV Utility Cost from First Year with a Negative Differential

	Coal Steam Green River 3	Coal Steam Green River 4	Coal Steam Tyrone 3	Gas CT Cane Run 11	Gas CT Haefling	Gas CT Paddy's Run 11	Gas CT Paddy's Run 12	Gas CT Zorn	All New Build
2006									$0
2007									$0
2008									$0
2009									$0
2010							($146)		$0
2011							$933		$0
2012							$1,975		$0
2013							$3,590		$0
2014							$4,515		$0
2015							$5,357		$0
2016							$6,181		$0
2017							$6,961		$0
2018	($2)	($38)	($49)				$7,702		$0
2019	($62)	($542)	($117)				$8,364		$0
2020	($385)	($704)	($286)				$8,983		$0
2021	($650)	($885)	($426)				$9,584		$0
2022	($1,110)	($1,433)	($879)				$10,149		$0
2023	($1,999)	($1,994)	($1,483)				$10,680		$0
2024	($2,483)	($2,695)	($2,431)				$11,175		$0
2025	($2,994)	($3,420)	($3,083)				$11,622		$0
2026	($3,485)	($4,500)	($3,717)				$12,058		$0
2027	($3,992)	($5,267)	($4,366)				$12,460		$0
2028	($4,541)	($6,094)	($5,033)				$12,845		$0
2029	($3,797)	($5,111)	($4,375)				$13,618		$0
2030	($3,371)	($4,203)	($3,769)				$14,325		$0
2031	($2,836)	($3,514)	($3,548)				$14,978		$0
2032	($2,378)	($2,924)	($3,172)				$15,574		$0
2033	($2,116)	($2,839)	($2,998)				$16,087		$0
2034	($1,879)	($2,552)	($2,847)				$16,565		$0
2035	($1,263)	($1,739)	($2,297)				$17,144		$0

F. Results – Phase 2:

Phase 2, utilized the demonstrated methodology from Phase 1. In developing the Reference Plan for Phase 2, a significant capacity shortfall occurs in 2013, primarily due to the large amount of candidate unit capacity "retiring" for the Reference Plan but also due to demand growth. Multiple coal fired technology units were required to overcome this shortfall. The numbers of each alternative unit required to cover the shortfall is shown in Figure 9.

Figure 9:

Capacity Additions to Cover 2013 Shortfall

Capacity Needed	
5190 MW	Includes Ghent 3 & 4, and Mill Creek 3 & 4
2895 MW	Excludes Ghent 3 & 4, and Mill Creek 3 & 4

	Max Capacity	Deration %	Summer Rating	Number to meet 5290 MW need	Number to meet 2895 MW need
LUSC	766	3.66%	737.9644	7.033	3.923
LGSC	766	3.50%	739.19	7.021	3.916
IGCC	611	10.97%	543.9733	9.541	5.322
LG_C	612.8	3.50%	591.352	8.777	4.896
CCCT	552	13.88%	475.3824	10.918	6.090
SCCT	181	18.23%	148.0037	35.068	19.560
IG_C	488.8	10.97%	435.17864	11.927	6.652
US_C	612.8	3.66%	590.37152	8.791	4.904

Note: Ghent 3 & 4, and Mill Creek 3 & 4 were initially considered as candidate units when the Phase 2 Reference Plan was developed. The Reference Plan shown for Phase 2 in Figure 2 was developed using the 5190 MW need in 2013. A Reference Plan using the 2895 MW need would have only required 4 LUSC units in 2013 to cover the reserve shortfall from "retiring" the Phase 2 candidate assets.

The final results for Phase 2 are presented in Figures 10 and 11. Most of the projected end of effective useful economic life schedules for this group of units fall in the 2026 to 2028 time frame: Ghent 1 in 2026, Ghent 2 in 2027, Mill Creek 1 and 2 in 2026, and all three Brown units in 2026. Brown 2 shows an early negative in 2015, but this should be ignored. Cane Run 4 retires in 2018, Cane Run 5 retires in 2022, and Cane Run 6 retires in 2023. Both of the hydro plants, Dix Dam and Ohio Falls, show an effective useful economic life throughout the study period.

Figure 10:
Phase 2
Present Value Utility Cost Differentials vs. All New Build Plan
(PVUC New Build - PVUC Existing Unit)

	Brown 1	Brown 2	Brown 3	Cane Run 4	Cane Run 5	Cane Run 6	Dix Dam	Ghent 1	Ghent 2	Mill Creek 1	Mill Creek 2	Ohio Falls	All New Build
2006	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2011	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2012	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2013	$6,166	$10,801	$33,006	$6,925	$9,499	$13,584	$3,066	$36,183	$40,630	$18,860	$19,578	$10,853	$0
2014	$4,981	$6,603	$30,791	$6,200	$8,619	$12,549	$2,971	$32,362	$37,562	$9,539	$18,224	$14,727	$0
2015	$2,668	($517)	$26,483	$2,979	$3,006	$9,212	$1,995	$29,656	$33,305	$13,778	$14,381	$11,769	$0
2016	$1,886	$3,517	$19,576	$66	$2,101	$1,036	$1,937	$22,755	$26,103	$7,816	$8,526	$11,618	$0
2017	$1,906	$3,527	$14,333	$65	$2,448	$3,453	$1,940	$16,888	$20,404	$5,457	$4,111	$11,611	$0
2018	$2,097	$3,893	$12,675	($1,838)	$2,878	$3,914	$1,942	$13,697	$17,454	$4,569	$6,633	$11,670	$0
2019	$2,063	$3,939	$11,906	$325	$2,800	$4,072	$1,910	$13,625	$16,298	$6,290	$6,559	$11,710	$0
2020	$2,036	$3,370	$12,128	$157	$2,585	$3,808	$1,910	$12,596	$15,884	$5,500	$6,097	$11,706	$0
2021	$1,478	$3,407	$12,156	$216	$2,696	$3,850	$1,921	$11,708	$15,528	$6,182	$6,085	$11,725	$0
2022	$840	$742	$5,231	($1,704)	($1,560)	$992	$1,753	$4,953	$8,190	$2,180	$2,425	$10,709	$0
2023	$735	$1,244	$4,634	($1,837)	$337	($1,187)	$1,786	$4,249	$7,412	$1,992	$2,130	$10,836	$0
2024	$518	$892	$3,623	($2,062)	$116	$187	$1,820	$3,195	$5,972	$1,392	$1,575	$10,892	$0
2025	$443	$804	$2,936	($3,979)	$14	$61	$1,801	$2,465	$5,416	$1,292	$72	$11,016	$0
2026	($202)	($32)	($1,187)	($2,709)	($750)	($1,067)	$1,682	($2,155)	$1,069	($1,226)	($166)	$10,469	$0
2027	($353)	($327)	($1,754)	($2,951)	($1,035)	($1,474)	$1,687	($3,070)	($73)	($740)	($599)	$10,574	$0
2028	($972)	($921)	($3,226)	($3,495)	($1,587)	($2,149)	$1,675	($4,410)	($1,680)	($1,469)	($1,446)	$10,698	$0
2029	($688)	($1,481)	($3,940)	($3,510)	($3,154)	($2,423)	$1,686	($5,255)	($2,529)	($1,850)	($1,746)	$10,674	$0
2030	($686)	($1,133)	($4,210)	($3,534)	($1,842)	($3,874)	$1,651	($5,706)	($3,007)	($1,988)	($1,939)	$10,457	$0
2031	($615)	($1,101)	($5,476)	($3,414)	($1,752)	($2,438)	$1,508	($6,844)	($4,038)	($1,955)	($1,795)	$9,508	$0
2032	($606)	($1,056)	($5,126)	($4,621)	($1,676)	($2,360)	$1,433	($6,321)	($3,695)	($1,845)	($1,801)	$9,090	$0
2033	($602)	($1,002)	($4,026)	($3,225)	($1,636)	($2,266)	$1,375	($5,346)	($2,598)	($1,690)	($2,300)	$8,723	$0
2034	($570)	($950)	($3,684)	($3,121)	($1,572)	($2,229)	$1,313	($4,729)	($2,568)	($2,115)	($1,593)	$8,316	$0
2035	($771)	($841)	($2,904)	($2,964)	($1,469)	($2,147)	$1,260	($3,645)	($1,940)	($1,347)	($1,449)	$7,968	$0

Figure 11:
Phase 2
Accumulated PV Utility Cost from First Year with a Negative Differential

	Brown 1	Brown 2	Brown 3	Cane Run 4	Cane Run 5	Cane Run 6	Dix Dam	Ghent 1	Ghent 2	Mill Creek 1	Mill Creek 2	Ohio Falls	All New Build
2006													
2007													
2008													
2009													
2010													
2011													
2012													
2013													
2014													
2015													
2016													
2017													
2018				($1,838)									
2019				($1,513)									
2020				($1,356)									
2021				($1,140)									
2022				($2,843)	($1,560)								
2023				($4,680)	($1,223)	($1,187)							
2024				($6,743)	($1,107)	($1,000)							
2025				($10,722)	($1,093)	($939)							
2026	($202)	($32)	($1,187)	($13,431)	($1,843)	($2,006)		($2,155)		($1,226)	($166)		
2027	($554)	($359)	($2,941)	($16,382)	($2,878)	($3,480)		($5,224)	($73)	($1,966)	($765)		
2028	($1,527)	($1,280)	($6,167)	($19,877)	($4,465)	($5,629)		($9,635)	($1,753)	($3,435)	($2,211)		
2029	($2,215)	($2,760)	($10,106)	($23,386)	($7,618)	($8,052)		($14,890)	($4,282)	($5,285)	($3,958)		
2030	($2,900)	($3,894)	($14,316)	($26,921)	($9,460)	($11,925)		($20,596)	($7,289)	($7,273)	($5,897)		
2031	($3,515)	($4,994)	($19,792)	($30,335)	($11,211)	($14,364)		($27,440)	($11,327)	($9,228)	($7,692)		
2032	($4,121)	($6,050)	($24,918)	($34,956)	($12,888)	($16,724)		($33,761)	($15,022)	($11,073)	($9,492)		
2033	($4,723)	($7,052)	($28,944)	($38,181)	($14,523)	($18,989)		($39,107)	($17,620)	($12,763)	($11,792)		
2034	($5,293)	($8,002)	($32,627)	($41,302)	($16,096)	($21,219)		($43,835)	($20,188)	($14,878)	($13,385)		
2035	($6,064)	($8,844)	($35,531)	($44,266)	($17,565)	($23,365)		($47,481)	($22,128)	($16,225)	($14,833)		

NewEnergy ASSOCIATES A Siemens Company

G. Summary

NewEnergy Associates, LLC performed a Life Assessment of E.ON U.S.'s generating assets to determine the effective useful economic lives of these assets. Figure 12 summarizes the results of this Life Assessment study and shows the projected end of useful economic life for E.ON U.S.'s coal fired steam assets. The assessment of the economics of continuing to operate E.ON U.S.'s combustion turbine assets; the Haefling units, Cane Run 11, Paddy's Run 11 & 12 and Zorn 1, indicates that these assets should continue to be economic throughout the time horizon of the study (through 2035).

Figure 12:

End of Economic Life

Unit Name	Projected End of Economic Life
Brown 1	2026
Brown 2	2026
Brown 3	2026
Cane Run 4	2018
Cane Run 5	2022
Cane Run 6	2023
Ghent 1	2026
Ghent 2	2027
Green River 3	2018
Green River 4	2018
Mill Creek 1	2026
Mill Creek 2	2026
Tyrone 3	2018

H. Appendices

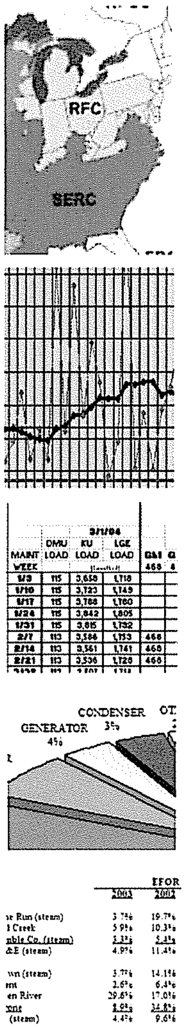
Appendix A
Project Tasks by Phase

Task No. / Phase No.	Task Description	Lead	Support	Comments
Task1, Phase 1	Develop a Strategist expansion plan with 600 MW of life assessment candidate units (out of a potential of 2,995 MW of life assessment candidate units) "retired in 2010 (CTs) and 2012 (coal) This plan will be the Phase 1 Life Assessment Reference Plan For the purposes of this study the E ON system will be modeled as an isolated system (i e - market sales and purchases will not be modeled).	NewEnergy	E ON	NewEnergy will rely on E ON data for this analysis, including all existing and new unit parameters, fuel costs, emission allowance costs, etc The cost of retiring units along with any unrecovered book costs will be incorporated into the revenue requirements of the Phase 1 Life Assessment Reference Plan New Energy will work with E ON to develop these costs in Task 2
Task 2, Phase 1	For each retirement candidate unit (or combination of units) develop cost data for (a) retiring the unit and (b) maintaining the unit in operation. For units that remain in operation develop forecasted operating parameters (EFOR, Scheduled outage requirements) if this will change as the unit continues operation	E ON	NewEnergy	NewEnergy will assist E ON in developing the cost framework and will review the results to ensure completeness Forecasted operating parameters will be E ON's responsibility
Task 3, Phase 1	Employing the "deferral capacity" logic in Strategist to keep installed reserves constant, add each retirement unit (or combination of units) back into the system and recalculate the expansion plan's costs Using the economic carrying charge to model the impacts of deferring investment costs, construct an economic ranking of all retirement candidates (or combination), showing the NPV of each candidate's impact vs the Life Assessment Reference Plan and the Year-by-year cumulative NPV Identify each life assessment candidate's retirement date using the approach described in this proposal.	NewEnergy	E ON	The deferral capacity logic in Strategist will permit the retirement candidate to be evaluated by keeping reserves or reliability (or a combination thereof) constant. It defers a rolling "slice" of new capacity, thereby incorporating the net capital and operating revenue requirements and dispatch impacts of the adjusted new capacity and the retirement candidate into the analysis
Task 4, Phase 1	Develop a draft PowerPoint presentation of results for E ON review and incorporate E ON comments to finalize it Present the results at E ON's offices in Louisville Prepare and transfer Strategist data files and other data used for the study to E.ON.	NewEnergy	E ON	
Task1, Phase 2	Develop a Strategist expansion plan for the remainder of the 2,995 MW of life assessment candidate units **not evaluated in Phase 1**. Incorporate any Phase 1 retirements into Phase 2 and develop a Phase 2 Life Assessment Reference Plan For purposes of this study, the E ON system will be modeled as it was modeled in Phase 1 (i e : as an isolated system, without any market sales and purchases).	NewEnergy	E ON	NewEnergy will rely on E ON data for this analysis, including all existing and new unit parameters, fuel costs, emission allowance costs, etc The cost of retiring units along with any unrecovered book costs will be incorporated into the revenue requirements of the Phase 1 Life Assessment Reference Plan New Energy will work with E ON to develop these costs in Task 2.
Task 2, Phase 2	For each retirement candidate unit (or combination of units) develop cost data for (a) retiring the unit and (b) maintaining the unit in operation For units that remain in operation develop forecasted operating parameters (EFOR, Scheduled outage requirements) if this will change as the unit continues operation.	E ON	NewEnergy	NewEnergy will assist E ON in developing the cost framework and will review the results to ensure completeness Forecasted operating parameters will be E ON's responsibility
Task 3, Phase 2	Same as Task 3, Phase 1	NewEnergy	E ON	Same as Task 3, Phase 1
Task 4, Phase 2	Same as Task 4, Phase 1 with the addition of a written report covering all assumptions, modeling and results from both Phase 1 and Phase 2.	NewEnergy	E ON	

Engineering
Laboratory

U.S.

Generation Services **Planning**



Life Assessment Study

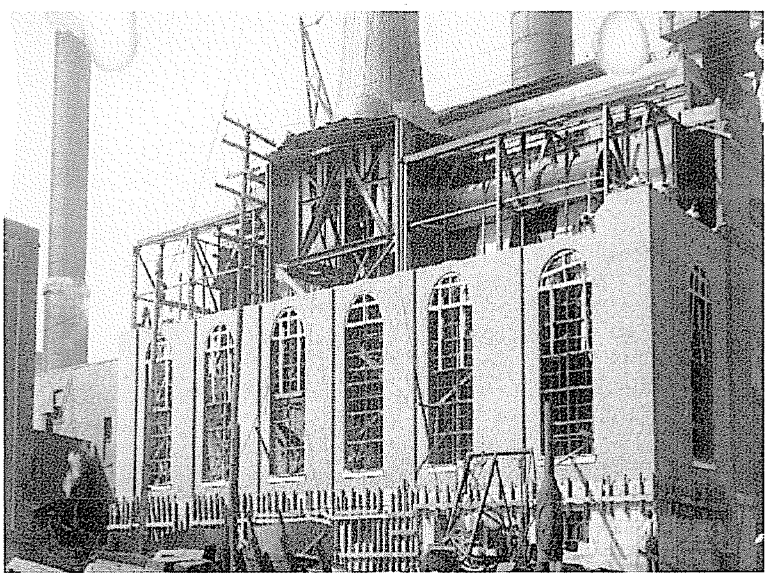
for

U.S.

Subsidiary

Louisville Gas and Electric's

Waterside Generating Plant



Submitted by
Generation Services

August 2006

Life Assessment Study: Phase II-Waterside 7-8

Table of Contents

Executive Summary

The turbines in use at Waterside Units 7-8 are 1960's vintage while the generators are from the early 1920's. Procurement of the necessary parts required to allow the units to reliably operate in a peaking role is getting more and more difficult as replacement parts become more costly to acquire and harder to locate. The low efficiency of the units, the forecasted high price of natural gas, the units' small capability and their age as well as increasing environmental obligations contribute to the small amount (440MWh) of forecasted energy expected to be generated by the Waterside Station through 2036.

The starting reliability of the Waterside Units has begun to decrease. In the last year in which Unit 7 or Unit 8 had attempted starts, the annual starting reliability was 43% and 67% respectively. Furthermore, since the year 2000, neither Unit 7 nor Unit 8 has achieved an annual FOR better (lower) than 33% or generated over 700MWh.

Detailed hourly computer models forecasting generation for the next thirty years (2007-2036) project essentially no energy production for the Companies' native load from the Waterside Units. The relatively high cost of Waterside generation is forecast to be economical for native load for only 8 hours of operation on Unit 7 and 32 hours of operation on Unit 8 over the entire 2007-2036 period. All of Unit 7's and 88% of Unit 8's projected service hours occur after 2018 when the generators associated with the units would be almost 100 years old and well beyond the estimated 10 year remaining life of the Group 3 units as indicated in the March 2003 evaluation of Group 3 Units[1]. Over the 30 year period, Waterside 7 and 8 are forecasted to generate only 88MWh and 352MWh for native load, respectively.

Therefore, based on the above, it is the recommendation to the Operating Committee that Waterside Units 7 and 8 be retired immediately.

[1] *Evaluation of Economic Viability of Group 3 Generating Units (Phase I),* March 26, 2003

Background

This analysis is a part of the Companies' continual supply-side resource assessment. In March of 2003 the Companies completed the first phase of a multiple phase life assessment evaluation of the Kentucky Utilities Company's (KU) and Louisville Gas and Electric Company's (LG&E) generating systems. In that assessment titled "*Evaluation of Economic Viability of Group 3 Units*" the Companies' generating units were categorized into three separate groups (Group 1, Group 2 and Group 3): Group 1 includes thirty-one units comprised of the lowest cost base-load units, the larger CTs and the hydro units; Group 2 includes eight units each currently operating well, but with generally higher operating costs; and Group 3 includes thirteen of the older, less efficient, more costly units that were expected to face significant economic challenges within the next 10 years. The March 2003 report recommended that all thirteen of the Group 3 generating units (totaling approximately 220MW) be evaluated in a subsequent life assessment evaluation to insure that the future challenges associated with operating these units are met in the most economic manner possible.

Generators Recommended for
Phase II of Economic Unit Viability Study

- Green River 1 and 2 (*Units Retired in 2004*)
- Tyrone 1 and 2
- Haefling 1, 2 and 3
- Waterside 7 and 8
- Paddy's Run 11 and 12
- Cane Run 11
- Zorn 1

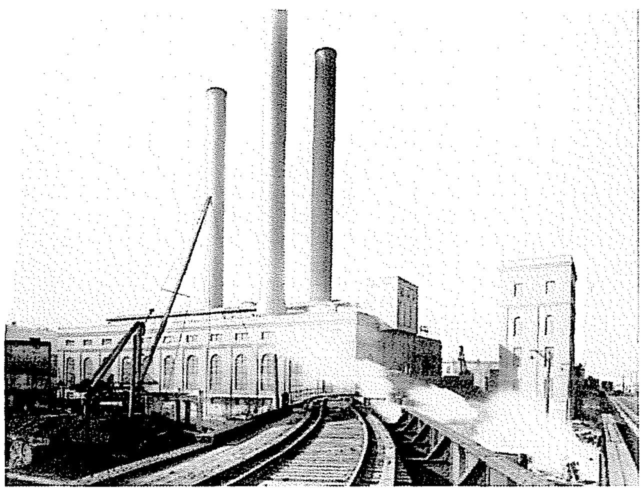
This analysis focuses on the Waterside Station (Units 7 and 8) identified in the March 2003 study as Group 3 units due to their age, high production cost and high heat rates. In addition, increasingly stringent environmental restrictions have negatively impacted the economics of the continued operation of Waterside Units 7 and 8. Furthermore, part procurement in order to reliably maintain the older, smaller, infrequently used units is becoming more difficult.

Reasons for Life Assessment Evaluation of Generating Units

1.	Unit Age
2.	Relatively High Production Cost
3.	Decline in Wholesale Market Prices
4.	Increasingly Stringent Environmental
5.	Increasing cost/frequency of maintenance related work combined with difficulty obtaining spare/replacement maintenance equipment

Waterside Units 7-8

The Waterside plant site is located in a former coal-fired power station in downtown Louisville, Kentucky and is LG&E's oldest generating facility still in operation. The plant's beginning dates back to a time before the 1913 consolidation, when one of LG&E's predecessor electric firms (Kentucky Electric Company), built a two-unit facility on the Ohio riverfront between Second and Third Streets. Waterside's capacity was expanded from time to time during the early 1900s. Coal Units 1, 2, 3 and 4 ranged from 2MW to 6.5MW. Unit 4 was relocated to the Waterside station from the generating station built at 14th and Magazine Streets in 1891. Units 5 and 6 were both 15MW generators that were placed in commercial operation in 1918 and 1920, respectively. Unit 7's 20MW generator (see **Appendix 1**) went commercial in 1923 and in 1925 LG&E installed the 25MW generator of Unit 8 (see **Appendix 1**). In 1964 the steam turbines of both Unit 7 and Unit 8 were replaced with natural gas consuming jet engines. All of Waterside's coal-fired units were eventually retired leaving the two gas-fired units of Waterside 7 and 8.



General View of Waterside Station from the North East (circa 1916)

The Waterside Units are the smallest at 11MW (net summer rating) and have the oldest generators still in-service of the Group 3 units in the LG&E generation system.

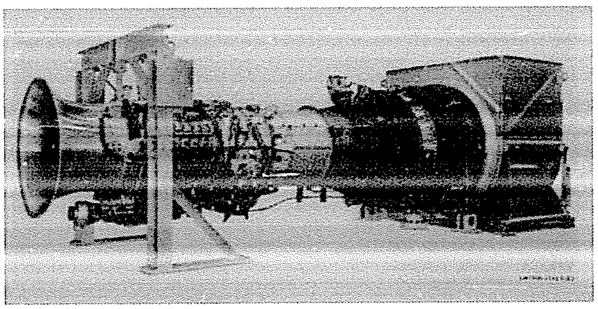
LG&E Group 3 Units

Age and Capability

Unit Type	Plant Name	Unit	Summer Rating (Net MW)	Turbine/Generator Set In-Service Year	Age (2006)
CT	Waterside	7	11	1964/1923*	42/83
CT	Waterside	8	11	1964/1925*	42/81
CT	Cane Run	11	14	1968	38
CT	Paddy's Run	11	12	1968	38
CT	Paddy's Run	12	23	1968	38
CT	Zorn	1	14	1969	37

* The original steam turbines have been replaced with 1960s vintage jet engines
The jet engines are connected to the original 1920's vintage electrical generators.

Each generating unit consists of two GE 7LM1500-PD101 industrial aero-derivative gas turbines without dual fuel capability (*see Pictures A and B*), which operate at 5523 rpm. Each pair of aero-derivative gas turbines drive through a common load gear (*see Pictures C and D*) to the original 1920's generators (*see Pictures E and F*), which run at 1800 rpm. A fuel gas compressor is located outside the main building in a dedicated enclosure. The gas turbines do not provide black-start capability. The units are started locally and the generation site is manned only during operation, typically during peak load periods. Unit 8 had both gas turbines replaced in 1999 following the failure of a turbine blade that damaged the gas turbine. The original gas turbines (CJ805) were obsolete and were replaced with a refurbished model J79, which was introduced by GE in 1955[2].



G.E. Model No. 7LM1500PD101

The difficulties associated with maintaining these 1960 vintage machines is evidenced by the May 2, 1999 letter from Maximum Turbine Support of California who

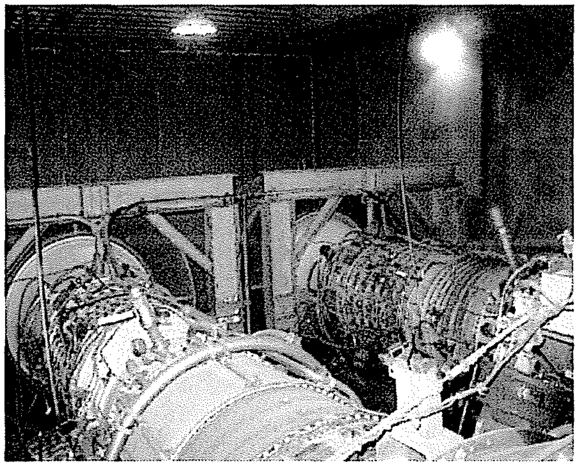
[2] See http://www.geae.com/engines/military/j79/index.html

was investigating the increased vibration of the one of the two turbines at Unit 8 during operation. Maximum Turbine Support attempted to disassemble the engine and remove the lock bolt that holds the turbine and the compressor rotors together. The following is an excerpt quoted from that letter (see **Appendix 2** for complete letter).

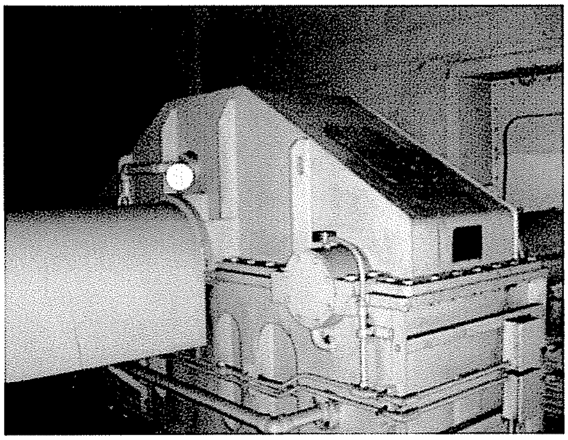
> "*Since the engine was produced in the 1960's and has to our knowledge never been dismantled, it was very difficult to disassemble. This engine is very rusty which caused us to break the turbine/compressor rotor wrench. This wrench is about 5-6 feet long and made of steel....After breaking the shops tool...we did finally move it, but only about two turns, and then it seized. We are not sure if it rolled a thread but it will not move.*"
>
> **Maximum Turbine Support, California (May 2, 1999)**

Other than to replace Unit 8's gas turbines there have been no other major overhauls, inspections or repairs to either turbine generating set.

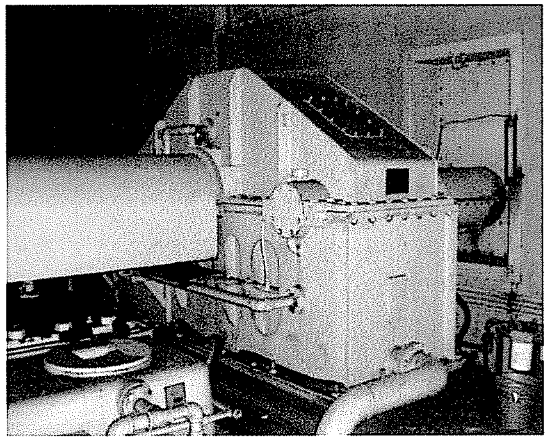
(Picture A)
Waterside Unit 7: Aero-Derivative Gas Turbines Under Easily Removable Moisture Protection Barrier



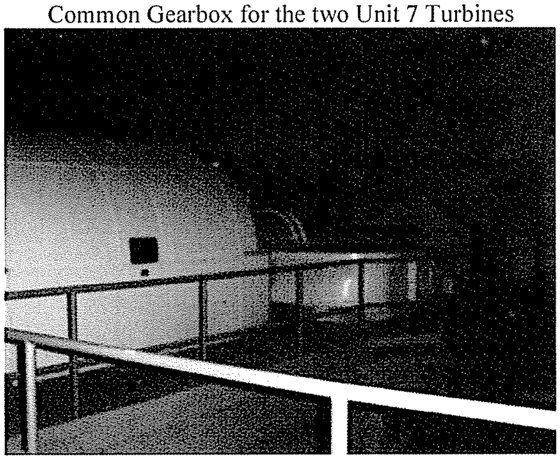
(Picture B)
Waterside Unit 8: Aero-Derivative Gas Turbines Moisture Protection Barrier Removed



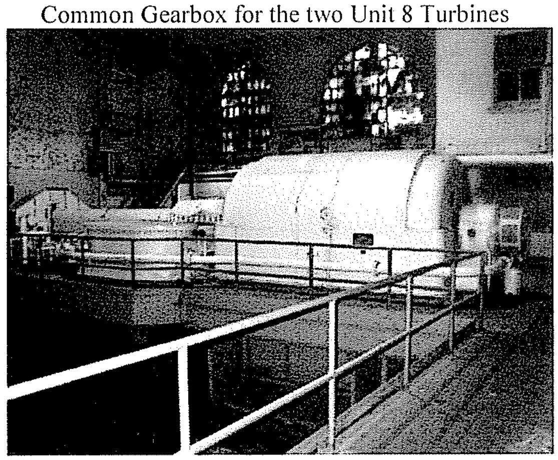
(Picture C)
Common Gearbox for the two Unit 7 Turbines



(Picture D)
Common Gearbox for the two Unit 8 Turbines

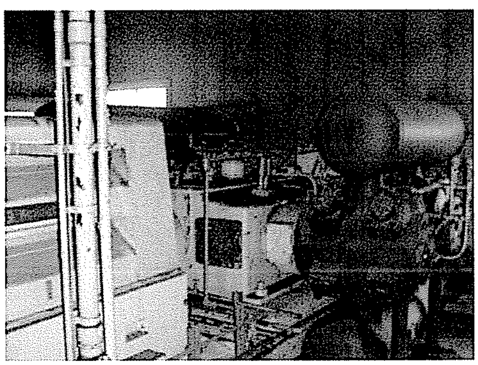


(Picture E)
Waterside 7-Original 1920's Vintage Generator



(Picture F)
Waterside 8-Original 1920's Vintage Generator

The gas compressor (*see Picture G*) was overhauled in 1996 and is working reliably; however it is now obsolete and replacement parts for it, like the turbines, are difficult to obtain.



(Picture G)
Waterside Units 7-8 Gas Compressor

There are a number of issues and concerns with the continued operation of both units, which would require significant investment to rectify and as a result it is difficult to justify capacity from these units as continuing to be available. As an example, the switchgear, DC rectifiers, relays and instrumentation is obsolete and repair parts are no longer available without first being reverse-engineered and then manufactured. The majority of the wiring insulation is asbestos, adding a significant cost to removal and replacement in kind. In original construction the insulation and gasket material contained high levels of asbestos and most of the painted surfaces contain high levels of lead, adding significant dollars to maintenance for the abatement of these components.

Historical Usage/Reliability

The greatest single year level of generation since 1982 on either of the Waterside Units obtained was just over 3,000MWh on Waterside Unit 7 in 1998. In 1999 Waterside 7 had a 5% forced outage rate (FOR) and yet still managed to generate only 1,800MWh. However, since the year 2000, neither Unit 7 nor Unit 8 has achieved an FOR better (lower) than 33% or generated over 700MWh.

Waterside Station Historical Data

Historical Service Hours			Historical Generation (MWh)		
Year	Unit 7	Unit 8	Year	Unit 7	Unit 8
1982	34	36	1982	433	468
1983	6	12	1983	69	138
1984	6	8	1984	72	105
1985	3	5	1985	33	77
1986	4	3	1986	44	43
1987	4	12	1987	42	97
1988	33	44	1988	417	541
1989	6	9	1989	87	126
1990	32	9	1990	413	114
1991	12	12	1991	156	153
1992	7	10	1992	94	115
1993	27	27	1993	344	348
1994	31	31	1994	437	415
1995	75	0	1995	1,001	0
1996	8	6	1996	120	88
1997	133	42	1997	1,774	521
1998	245	15	1998	3,045	174
1999	138	19	1999	1,750	224
2000	57	41	2000	691	474
2001	6	5	2001	68	62
2002	2	2	2002	13	19
2003	0	0	2003	0	0
2004	0	0	2004	0	0
2005	0	0	2005	0	0
Total	869	348	**Total**	11,103	4,302

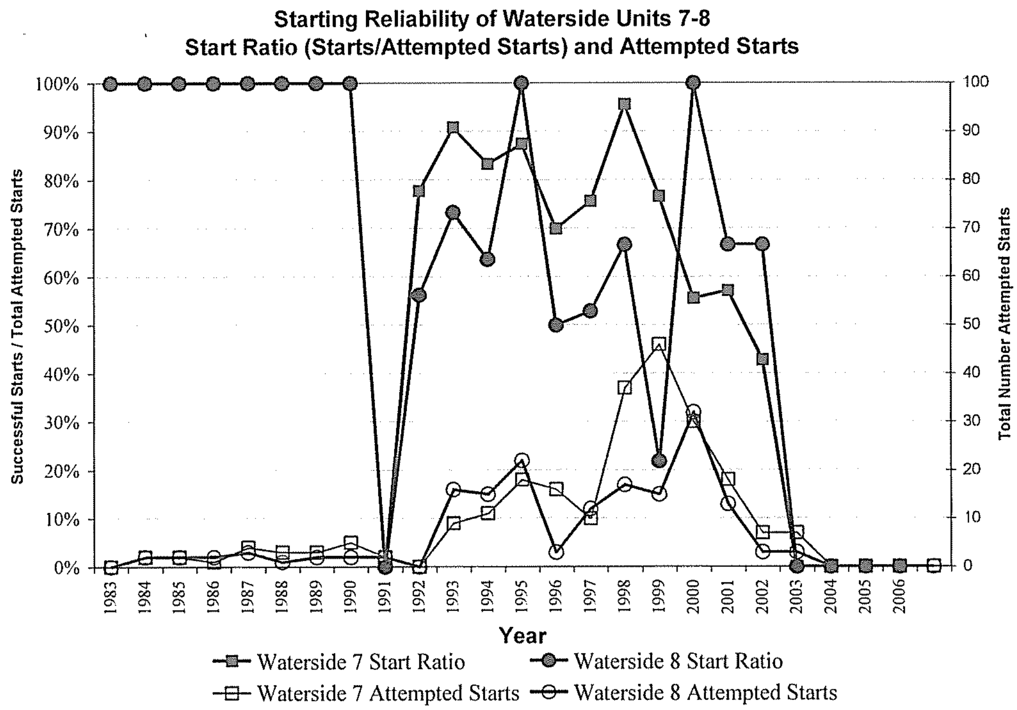
Waterside Station

Forced Outage Rate

Year	Unit 7	Unit 8
1999	5%	100%
2000	80%	94%
2001	93%	82%
2002	98%	33%
2003	N/A	N/A
2004	N/A	N/A
2005	100%	100%

N/A- Implies service hours and forced outage hours are 0.

With high production costs, the units are most likely to operate in times of high demand. A reasonably high confidence level associated with the starting ability of peaking units is necessary in order to avoid unexpected purchases of high-priced market power. Since the early 1990's, the starting reliability of the Waterside Units has begun to decrease. In the last year that Unit 7 or Unit 8 had attempted starts, the annual starting reliability was 43% and 67% respectively.



Forecasted Production Value

Waterside 7 and 8 (~18,000 Btu/kWh) are among the least efficient of the LG&E units (~18,000 Btu/kWh). The Units' high heat rate, high fuel price (August 2006 natural gas price of approaching $8/MCF) result in a total generation cost of $150/MWh, also among the highest on the LG&E system. Detailed hourly generation forecast for the next thirty years (2007-2036) projects essentially no energy production for the Companies' native load as the high cost Waterside generation is forecast to be economical for only 8 hours of operation on Unit 7 and 32 hours of operation on Unit 8 over the entire 2007-2036 period. All of Unit 7 and 88% of Unit 8's projected service hours occur after 2018 when the generators associated with the units would be almost 100 years old and well beyond the estimated 10 year life of the Group 3 units. Service hours on Unit 8 slightly exceed those of Unit 7 due to Unit 8's slightly better heat rate. Over the 30 year period, Waterside 7 and 8 are forecasted to generate only 88MWh and 352MWh, respectively.

Waterside Station Forecast Data

Service Hours			Generation (MWh)		
Year	Unit 7	Unit 8	Year	Unit 7	Unit 8
2007	0	0	2007	0	0
2008	0	0	2008	0	0
2009	0	0	2009	0	0
2010	0	0	2010	0	0
2011	0	0	2011	0	0
2012	0	4	2012	0	44
2013	0	0	2013	0	0
2014	0	0	2014	0	0
2015	0	0	2015	0	0
2016	0	0	2016	0	0
2017	0	0	2017	0	0
2018	0	0	2018	0	0
2019	4	4	2019	44	44
2020	0	12	2020	0	132
2021	0	0	2021	0	0
2022	0	0	2022	0	0
2023	0	0	2023	0	0
2024	0	0	2024	0	0
2025	0	0	2025	0	0
2026	4	4	2026	44	44
2027	0	0	2027	0	0
2028	0	0	2028	0	0
2029	0	4	2029	0	44
2030	0	0	2030	0	0
2031	0	0	2031	0	0
2032	0	0	2032	0	0
2033	0	4	2033	0	44
2034	0	0	2034	0	0
2035	0	0	2035	0	0
2036	0	0	2036	0	0
Total	8	32	**Total**	88	352

100% of Unit 7 and 88% of Unit 8's future utilization is projected to occur after 2018.

Environmental Challenges

Compliance with environmental laws and regulations continues to drive costs upward. As an example, Waterside Units 7-8 must conform to the USEPA's Spill Prevention, Controls and Countermeasures (SPCC) regulations approved on November 28, 2005 and effective October 31, 2007. The regulations require preventive measures to reduce the likelihood of an oil release from bulk storage containers, oil filled equipment and/or oil filled manufacturing equipment from reaching a navigable watercourse. In the case of the Waterside station, the navigable watercourse would be the Ohio River, via direct discharge or conveyed by the facilities storm water management system. However, in conjunction with the SPCC requirements, the Jefferson County Hazardous Materials Prevention Control (HMPC) plan would also require a mechanism to prevent a release to the sanitary sewer system.

On December 9, 2005 representatives from Fuller, Mossbarger, Scott and May, Engineers (FMSM) made a SPCC assessment of the Waterside Station. On January 24, 2006 FMSM provided cost estimates for compliance with SPCC at Waterside (see **Appendix 3** for the complete FMSM letter). The recommendations FMSM made and their associated cost could exceed $204,000 and are enumerated below:

Action	Cost Estimate ($)
1. Replace 500 gallon fuel oil tank	($26,250-$45,000)
2. Modify Transformer on North Side of Building	($6,000-$13,000)
3. Generation lubrication containment	($22,000-$45,000)
4. Unit Reservoir Lubricating System Containment	($26,000-$63,000)
5. CT Containment Area floor and floor drain	($1,500-$3,000)
6. 55- Gallon Drums and Portable Spill-Pallets	($3,150-$5,500)
7. Install an oil/water separator prior to discharge	($15,000-$30,000)

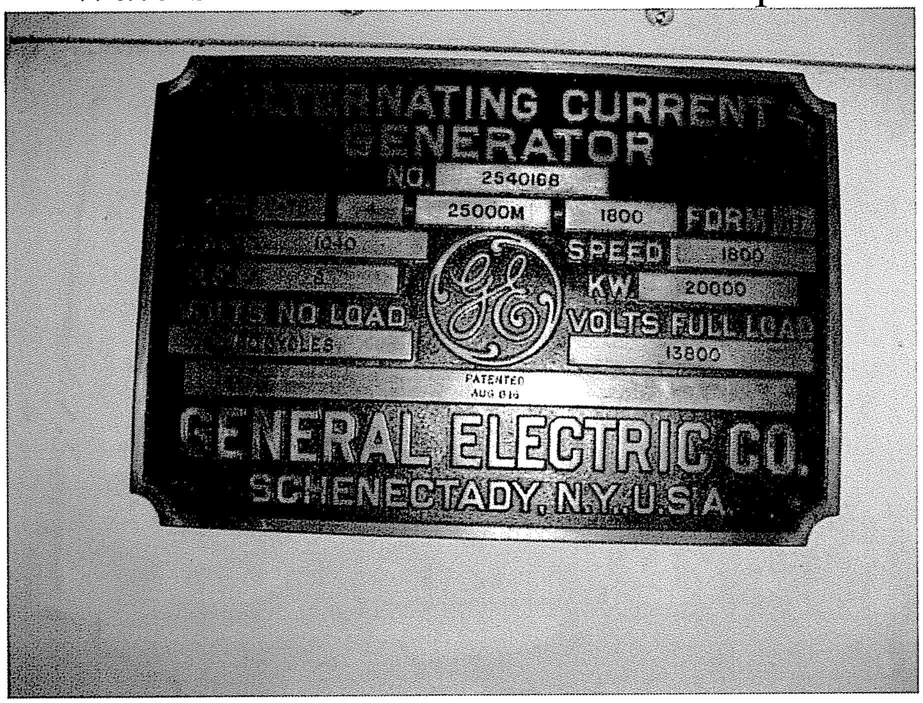
Presently, plans are to drain the lube oil from the associated equipment and store in a compliant offsite location.

Conclusion and Recommendation

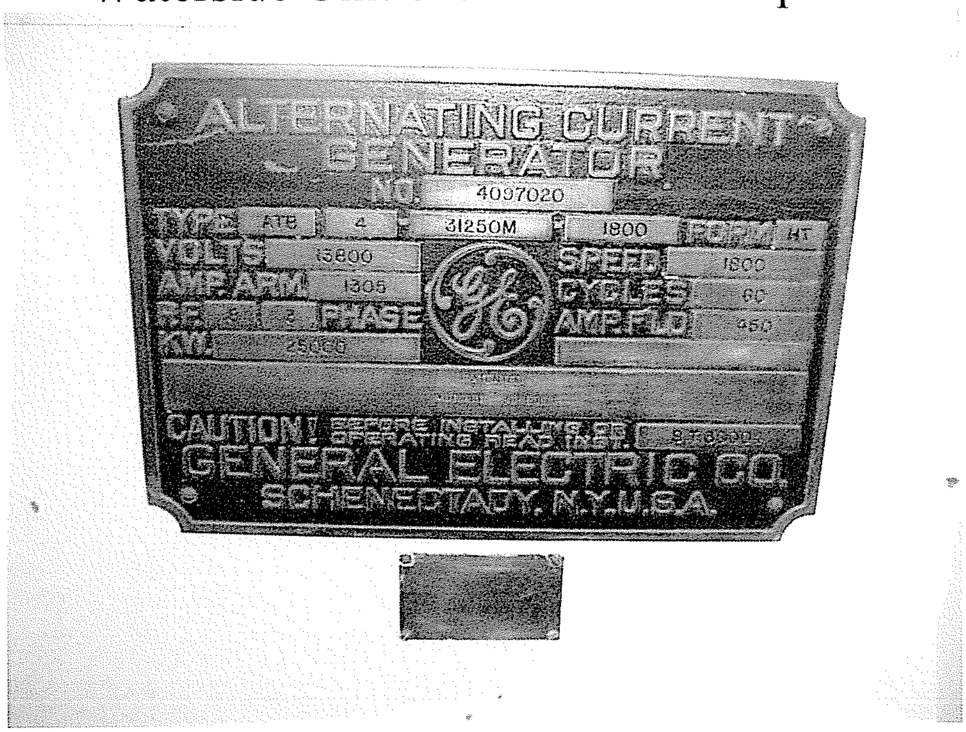
The generators associated with Waterside Units 7-8 have been in-service since the 1920's and the turbines are 1960s vintage technology. Procurement of the necessary parts required to allow the units to reliably operate in a peaking role is getting more difficult as replacement parts for the turbine, generator and gas compressor become more costly to acquire and harder to locate. The high heat rates of the Units, the high price of natural gas fuel, their small capacity as well as their age and environmental regulations make it economically prudent to retire Waterside Units 7 and 8. Therefore, it is recommended that Waterside Units 7 and 8 be retired from operation effective immediately.

Appendix 1

Waterside Unit 7 Generator Nameplate



Waterside Unit 8 Generator Nameplate



Appendix 2

115 E. La Salle St.
Redlands, CA 92374
Phone (909) 794-8493 Fax (909) 794-9238

May 2, 1999

L G & E

Fax: 502-627-2857

Gordon,

I am writing this letter to explain what we feel is the problem with your engine, which we currently have at our shop. Since this engine was produced in the 1960's and has to our knowledge never been dismantled, it was very difficult to disassemble. This engine is very rusty which caused us to break the turbine / compressor rotor wrench. This wrench is about 5-6 feet long and made of steel. We had a 1" impact along with a cheater bar and could not move the nut. After breaking the shops tool we sent them ours and it was with this one we did finally move it, but only about two turns, and then it seized. We are not sure if it rolled a thread but it will not move.

We did a visual inspection of the turbine rotor to determine if the baffles had come apart, which was one of our theories as to what was causing the vibration in this engine. They appeared to be in good shape. We then did a sump pressure check on the number two bearing area. This sump should hold pressure for two to five minutes, yours held for only 9 seconds. So we are now at a cross roads, do we cut the engine apart to confirm what we feel we already know, that oil has gotten into your compressor rotor from the # 2 sump, and is causing the vibration? If we do take this course of action it is just to confirm our theory as it will destroy the compressor and turbine rotors. I should also point out that every time we move this engine we get more oil running out of it. It is very hard to get the oil out of your rotor and very time consuming, we would not think of disassembling and repairing your rotor as this in itself would run the cost past the quoted 125,000.00.

As stated earlier, the engine because of the type of climate it "lives" in, which is very moist, the outside components are also very rusty and the following ones do not meet the requirements for return to service. The combustion cases, compressor rear frame, rear compressor stator cases. Some other items will need repair, the first stage nozzle needs overhaul, the leading edge is too thin and does not meet the requirements for return to service. The number two carbon seals, as well as the air seals would all need to be overhauled. One problem that comes into play when we are replacing these items is that because of the vintage of your engine identical replacement parts are not available. We do have replacement spares, but they are a more current configuration. This creates a new

FAXED 5-2-99

problem which is they are not compatible with some of your older items. So this brings us to the list of other items we would have to replace, 17th stage air seals both rotating and stationary. We also need to replace the compressor rotor, but this again creates the configuration problem with parts. Your rotor is different because it has two # one carbon seals on the front stub shaft, others only have one. Therefore, we would have to change your front frame to conform to the new rotor.

With the above information and the following quote on parts you can see that a replacement engine is the only way to go, since parts put you over the 125,000.00 we quoted. There are also some very distinct advantages to having a replacement engine. One is replacement parts are now readily available, well into the year 2010. Your engine will be much more reliable and durable.

I do feel it is my responsibility to advise you that your best course of action would be to replace both engines in this one skid and make one unit "rock solid." The parts from your old engines could be used to support the other unit you are running. We can offer a performance guarantee of 18-20 MW's depending on the loses we experience from the other rotating equipment. We also offer a two year warranty on these engines.

Here is the quote on the parts to repair your engine, this does not include the parts damaged as a result of further disassembly of your engine.

Combustion cases	$ 9,500.00
Compressor rear frame	$ 19,500.00
Compressor rear stator cases	$ 37,500.00
First stage nozzle overhaul	$ 12,500.00
17th stage air seals	$ 6,500.00
No. 2 carbon seal	$ 5,000.00
Overhauled compressor rotor	$ 80,000.00

I hope this answers your questions and gives you some additional information to make a decision. Look forward to hearing from you in the coming days.

Best Regards,

Randy

Randy Lincoln

Appendix 3

FMSM ENGINEERS

1901
Nelson Miller Parkway
Louisville, Kentucky
40223-2177

502-212-5000
502 212 5055 FAX

www.fmsm.com

January 24, 2006 LV2005159L01

Roger Medina
Senior Chemical Engineer
E.ON US
220 West Main Street
Louisville, KY 40202

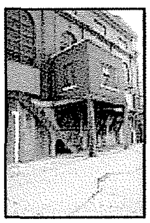
Re: Cost Estimate
Waterside Generating Station
SPCC Compliance

Dear Mr. Medina:

Fuller, Mossbarger, Scott and May, Engineers Inc. (FMSM) has been requested to provide a cost estimate for updating the Waterside Generating Station's oil storage units to conform with the new Spill Prevention, Controls and Countermeasures (SPCC) regulations, as amended on November 28, 2005. The regulations require preventive measures to reduce the likelihood of an oil release from bulk storage containers, oil filled equipment and/or oil filled manufacturing equipment from reaching a navigable watercourse. In the case of the Waterfront Generating Station, the navigable watercourse would be the Ohio River, via direct discharge or conveyed by the facilities storm water management system. However, in conjunction with the SPCC requirements, the Jefferson County Hazardous Materials Prevention Control (HMPC) plan would also require a mechanism to prevent a release to the sanitary sewer system.

On December 9, 2005, FMSM accompanied representatives' of E.ON U.S. during a SPCC assessment of the facility. During that site visit, the following observations were made:

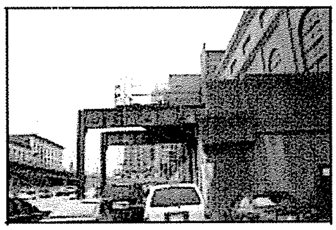
500-gallon Bulk Storage Tank



The bulk storage tank located on the roof of the generating station does not meet the SPCC requirements for the following reasons:

- The bulk storage tank does not have containment as required by 112.8(c),
- The tank does not have fail safe engineering,
- The tank and piping has not been integrity tested,
- The transfer area does not meet the general containment discharge provisions of 112.7(c). Discharges from the current barrier around the tank either infiltrate directly into the soil or a captured by the storm water drainage system and discharged off the site.
- The tank system probably needs a fusable link valve to isolate the gravity discharge from the tank during a fire.

External Transformers on Northside of Building

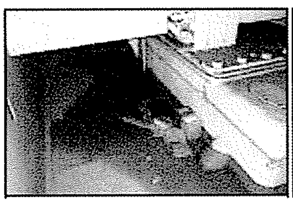
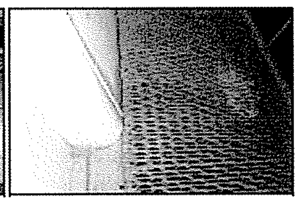



The electrical transformers on the steel floor grating do not meet general containment requirements of the SPCC rules for the following reasons:

- The oil filled electrical equipment does not have containment per 112.7(c),

Any release of oil from the system from the elevated structure onto the asphalt parking lot below. The asphalt parking lot is sloped in order to transport stormwater to the northeast stormwater catch basin, which discharges into the Ohio River.

Unit Generating Lubrication System

The Unit Generating Lubrication System does not meet the SPCC requirements for the following reasons:

- The oil filled equipment does not have containment per 112.7(c).

The oil filled equipment does not meet the general containment requirements of the SPCC rules. A large release from the equipment would result in the flow of oil from the ground floor of the building into other portions of the structures. Due to the unpredictable flow path of the oil, the material could enter floor drains, concrete cracks, and or the basement sump discharge system and enter the environment.

Unit Reservoir Lubricating System

The Unit Reservoir Lubrication System does not meet the SPCC requirements for the following reasons:

- The oil filled equipment does not have containment per 112.7(c),
- Currently, these reservoirs are single walled tanks that do not have passive secondary containment in their immediate vicininty. It appears, based on the site visit and review of previous plans, that secondary containment was sought through the position that the building acts as a large containment vault.

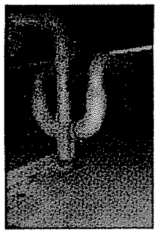
55-gallon Totes and Portable Tanks

The Portable and Mobile Tanks do not meet the SPCC requirements for the following reasons:

- The ASTs do not have containment per 112.8(c),

55-gallon drums and portable totes were observed in numerous locations throughout the facility. During our visit, these tanks were not located within the immediate confines of a secondary containment system. The argument could be made that the building provides a level of containment, and that approach will be further discussed in the following paragraph.

Facility Sump Opertaion

Whether by original design or not, the basement floor of the building periodically accumulates water from unknown sources, presumably storm water diverted by drains into the basement, stormwater infiltration through cracks in the structure, or possibly infiltration of river water during high water events. Temporaty sump pumps, operated by level floats, were installed in the basement and periodically discharge accumulated water either to a storm or sanitary discharge point. The current system does not use a method to monitor for the potential discharge of oil from the sump system.

- Lastly, sump pumps are installed in the basement of the building. The basement is located approximately 10+ feet below the normal river stage. Water, either storm water that has infiltrated into the building after storm events or river water that has percolated through the floor of the building accumulates in the basement of the structure. This water is currently pumped out of the basement of the building by temporary sump pumps. These pumps are automatically operated by a float sensor built into the pump and convey, through a large diameter hose, the collected water to a discharge point (trident). In the event of a release of oil inside the structure, there is a very good chance that the oil could eventually flow to the water collection system and be discharged without inpsection.

Recommendations

In order to achieve the minimum compliance level required, the following recommendations are proposed, along with a estimated cost to implement.

500-gallon Fuel Oil AST

The 500-gallon diesel fuel oil tank should be replaced with a new double walled AST. The tank design should include fale safe engineering, such as a visual gage for tank gauging and an intersitual indicator for direct observation. If the tank continues to receive fuel from a filling gas types dispenser, overspill protection should be provided to mitigate small spills that may occur during the fueling process. In addition, the new tank should include a fusable link valve to isolate the gravity discharge of the tank in the event of a fire at the facility. The ball park cost range for these activities is **$26,250 to $45,500** and includes the following:

- Old AST tank cleaning and removal from building rooftop.
- Structural evaluation structural and minimal repair of existing roof top to accept new tank.
- Purchase of new 500-gallon double walled AST with fuel gauge and intersitual indicator.
- Placement and secure AST on existing structure.
- Construct roll-over berm in loading to meet the provisions of 112.7(c) to protect stormwater discharge system from releases during tank loading.
- Install a fusable link valve on the fuel piping immediately after it enters the building.
- Pressure test the new system as part of the initial system installation.

Transformer on Northside of Building

Due to the ability for wind to blow an oil release outside of any containment installed directly beneath the transformers, a form of vertical shielding needs to be installed to direct a release directly beneath the transformers and a form of containment constructed beneath the units. The ball park cost range for these activities is **$6,000 to $13,000** and includes the following:

- Installation of a exterior shield to minimize the air entranment and transport of oil during a transformer release,
- Construction of an asphalt berm beneath the transformer structure, and
- The use of CI Agent on the lowermost containment point, inorder to create a stormwater discharge threshold that will allow for the discharge of oil free water but create a checmical barrier in the event of an oil release.

Unit Generating Lubrication System

In order to create a more controlled environment in the immediate vicinity of the generating turbines, it is recommended that the existing steel floor grating be filled with a low permeable material (i.e., concrete) and that the turbines be surrounding by a concrete dike capable of holding 1/3 of the oil within the equipment. The ball park cost range for these activities for **two units is $22,000 to $45,000** and includes the following:

- Equipment clean up and repair of existing gaskets or equipment causing weeps/seeps/leaks,
- Filling of steel floor gating with low permeable material, and
- And construction of passive containment dike.

Unit Reservoir Lubricating System

In order to create a more controlled environment in the immediate vicinity of the generating turbines, it is recommended that the existing steel floor grating be filled with a low permeable material (i.e., concrete) and that the turbines be surrounding by a concrete dike capable of holding 1/3 of the oil within the equipment. The ball park cost range for these activities for two units is **$26,000 to $63,000** and includes the following:

- Equipment clean up and repair of existing gaskets or equipment causing weeps/seeps/leaks,
- Repair piping,
- Filling of steel floor gating with low permeable material, and
- And construction of passive containment dike.

CT Containment Area

In order to create a more controlled environment in the immediate vicinity of the CT turbines, it is recommended that the existing floor and floor drain be sealed. In order to accomidate the periodic draining of accumated precipitation, the floor drain will be equipped with an easily removed plug or stopper. The ball park cost range for these activities for two units is **$1,500 to $3,000** and includes the following:

- Caulking cracks in existing floor, and
- Rubber stopper for floor drain.

This cost estimate does not include the increase in maintenance required to ensure the proper management of precipitation accumulation.

55-gallon Drums and Portable Totes

Based on current inventory documents, it is estimated that between 10 and 15 55-gallon drums are located throughout the facility. Some drums may be located in areas that provides competent secondary containment, but due to the portability of the containers, and the observations during the site visit, it is recommended that all 55-gallon drums be lpaced no spill-pallets. The ball park cost range for these activities for two units is **$3,150 to $5,500** and includes the following

- 8 spill pallets capable of storing 2 drums each.

Facility Sump Operations

Permanent and portable sump pumps operated in the basement of the building and underlying structure present a challenge in controlling the unplanned discharge of oil into the storm or sanitary sewers. In order to mitigate the unplanned conyance and/or discharge of an oil release by these pumps, a fail safe engineering device needs to be included either in front (oil sensors) or behind the pump operation (oil/water separator). Given that the containment, storage and pump operation of the existing system is not well understood (e.g., location of pump inlets, whether oil would uniformly disperse in sump for detection, etc.) the conservative alternative would be to install a pre-discharge oil/water separator that could be used during normal flow conditions. This normal flow stream would be supplemented and the fail safe by-passed during river flooding events. The ball park cost range for these activities for the pretreatment system is **$15,000 to $30,000** and includes the following

- Portable oil/water separator capable of a nominal flow of 100/gallons per minute with a 100-gallon oil reservoir.
- Lift pump to transfer contents from water side of separator to discharge point at 100 gpm and 100 total dynamic head.

While there are many uncertainties in the development of the current cost estimate, we believe that the estimate represents the level of accuracy communicated to FMSM for cost development purposes. The recommendations included in this cost estimate are based on discussion between FMSM and E.ON U.S. represenatives and does not represent the universe of options that may be available to achieve SPCC compliance. The total cost range for these recommendations is **$99,900 and 205,000.**

FMSM is looking forward to working with you to further define the scope of services that may be required for SPCC compliance at the Waterfront Generating Station. Please review this cost estimate and contact me with any questions or comments at (614) 844-4007.

Sincerely,

FULLER, MOSSBARGER, SCOTT AND MAY
ENGINEERS, INC.

Brad Rodgers

Bradley S. Rodgers, EI, CHMM
Project Manager

/jfk

Evaluation of Economic Viability of Group 3 Generating Units (Phase I)

Kentucky Utilities Company

And

Louisville Gas and Electric Company

Prepared by: Generation Services

March 24, 2003

Evaluation of Economic Viability of Group 3 Units (Phase I)

-Table of Contents

Executive Summary

Executive Summary

The age of the Companies' generation fleet together with increasing environmental compliance costs, depressed wholesale market conditions and increased maintenance costs suggest that improved corporate financials can be realized through retirement of some of the older, less efficient electric plant. The Companies have completed the first phase of a two phase study evaluating the economic feasibility of continuing to operate the older units on the KU and LG&E systems. Phase I identifies the units within the KU/LG&E system that should be evaluated in Phase II by making a high-level review of the incremental economic impacts associated with retirement of each unit. Included are the cost impacts associated with fuel, O&M, SO_2 and NO_x emissions, insurance, depreciation and unit capacity. Phase II will commence with the units identified by this study and will evaluate in detail each of the options available to the unit so as to insure the future challenges associated with operating these units are met in the most economically possible way.

The Companies generating units have been categorized into three separate groups: Group 1 includes 31 units comprised of the lowest cost base-load units, the larger CTs and the hydro units, Group 2 includes 8 units each currently operating well but with generally higher operating costs and Group 3 includes 13 of the older, less efficient, more costly units that are expected to face significant economic challenges within the next ten years. This analysis focuses solely on the 13 units in Group 3 totaling approximately 220MW of KU/LG&E capacity.

An incremental financial evaluation was performed that quantified the additional costs or savings resulting from retirement of each unit in Group 3. The evaluation was performed from three perspectives: a Regulated Environment using a Revenue Requirements Analysis, a Regulated Environment using a Cash Flow Analysis, and a Merchant Environment again using a Cash Flow Analysis. In addition to the Base Assumptions, sensitivities around the value of capacity and the price of purchased power were conducted.

Generation Services recommends, based on the results of the financial evaluation, that all 13 units in Group 3 and shown in the table below be evaluated in Phase II of this study. Furthermore, it is recommended that if a simultaneous evaluation of these units can not be performed in Phase II, then Green River 1-2 be the first units evaluated since, based on this evaluation, the economics of these two units support retiring in the most scenarios, thereby potentially offering the most substantial and immediate cost savings.

Generators Recommended for
Phase II of Economic Unit Viability Study

- Green River 1 and 2
- Tyrone 1 and 2
- Haefling 1, 2 and 3
- Waterside 7 and 8
- Paddy's Run 11 and 12
- Cane Run 11
- Zorn 1

Background

Periodically the economics surrounding the continued operation of the units on the Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E) generating systems are reviewed to ensure the efficiency of the overall system. The generating units across the Companies' fleet continue to age and thus require evaluation to review the economic operation of the units. Some of these units have operated past their design lives and thereby run a greater risk of a catastrophic failure than other units. An example of such occurred in November of 2001 when KU's Pineville Unit #3 (circa: 1951) experienced a generator failure. The failure was such that a subsequent evaluation recommended the most economic decision was to retire the unit and close the facility rather than to repair the damage and continue operation. In addition, the relatively high production costs of some units combined with the recent decline in wholesale market prices and increasingly stringent environmental restrictions, most recently the Clean Air Act Amendments (CAAA) of 1990, will only worsen the economics of continued operation of some units. The upcoming NO_x environmental restrictions will allow for the totaling of NO_x emissions over the Companies' entire system during the ozone season and do not require reduction at the unit level. Given the ability to comply on a system-wide basis the Companies will be reducing NO_x emissions more than required on some of the generating units in order to emit below the combined system tonnage cap of 12,447 tons. For example, the Companies are installing Selective Catalytic Reduction systems (SCRs) on at least six generating units and additional NO_x control technologies are underway on nearly every generating unit in the system. Furthermore, the questions surrounding the economics of more frequent and often costly maintenance on older units are becoming more difficult to address.

Table 1
Reasons for Currently Evaluating Economic Viability of Generating Units

1.	Unit Age
2.	Relatively High Production Cost
3.	Recent Decline in Wholesale Market Prices
4.	Increasingly Stringent Environmental Restrictions (i.e. Clean Air Act of 1990) which target SO2 and NO_x reduction
5.	Increasing cost/frequency of maintenance related work combined with difficulty obtaining spare/replacement maintenance equipment
6.	Future Environmental Compliance Costs (carbon tax, mercury reduction)

For the reasons shown in Table 1 above, the Companies initiated a two-part study in November 2002 to address the economics of continued operation of the older units on the KU and LG&E system. This is the first phase of a multi-phase evaluation to identify those units most likely to be affected. Subsequent evaluations will begin with the units identified by this study and will evaluate in detail each of the options available to the unit so as to insure the future challenges associated with operating these units are met in the most economical way possible.

Discussion of Unit Groupings

The Companies' generating units have been categorized into three basic groupings. Group 1 includes the lowest cost, most efficient base-load units expected to be operational for 20 or more years without any significant issues. Most of these are also the newest units on the KU/LG&E system, with the exception of the hydro units. Group 2 includes units that operate well, but have somewhat higher operating costs. These units are currently not expected to have significant economic challenges during the next ten years but may have issues surface beyond ten years. Group 3 consists of mostly peaking units with individual unit capacities of 30MW or less. These units are older and more costly to operate and maintain.

This analysis focuses on the Companies' Group 3 units. Group 3 units are expected to face significant economic challenges in the near term (less than ten years out). Challenges include complying with new environmental requirements in an economic manner, maintaining a unit in reliable working condition despite its age, and the risk of obsolete replacement parts. Thirteen different units are identified as Group 3 units at seven different plant locations totaling approximately 220MW of KU/LG&E summer capacity. The nine CTs in this group operated for a combined total of 40 hours in 2002, while Tyrone 1-2 have no service hours for two of the last three years. The remaining two units in Group 3 (Green River Units 1 and 2) operated just over 10 weeks (~1,700 service hours) each in 2002. Table 2 follows, which shows the KU/LG&E units and their corresponding Group as well as other relevant data. Ten years of service hours for units in each of the three groups (excluding the hydro units of Group 1) are shown in Appendix A at the end of this report.

Table 2
KU/LG&E Generators in Group 1, 2 and 3

Type of Unit	Plant Name	Unit	Summer Capacity (MW)	In Service Year	Age (2002)
Group 1					
Steam	Brown	3	429	1971	31
Steam	Ghent	1	509	1974	28
Steam	Ghent	2	494	1977	25
Steam	Ghent	3	496	1981	21
Steam	Ghent	4	467	1984	18
Steam	Mill Creek	1	308	1972	30
Steam	Mill Creek	2	306	1974	28
Steam	Mill Creek	3	391	1978	24
Steam	Mill Creek	4	480	1982	20
Steam	Trimble Co	1	386	1990	12
CT	Brown	5	134	2001	1
CT	Brown	6-7	154 each	1999	3
CT	Brown	8, 10	130 each	1995	7
CT	Brown	9	130	1994	8
CT	Brown	11	130	1996	6
CT	Paddy's Run	13	158	2001	1
CT	Trimble Co	5-6	155 each	2002	0
Hydro	Ohio Falls	1-8	6 each	1928	74
Hydro	Dix Dam	1-3	8 each	1925	77
Group 2					
Steam	Brown	1	104	1957	45
Steam	Brown	2	168	1963	39
Steam	Cane Run	4	155	1965	37
Steam	Cane Run	5	168	1966	36
Steam	Cane Run	6	240	1969	33
Steam	Green River	3	68	1954	48
Steam	Green River	4	100	1959	43
Steam	Tyrone	3	71	1953	49
Group 3					
Steam	Tyrone	1	27	1947	55
Steam	Tyrone	2	31	1948	54
Steam	Green River	1-2	22 each	1950	52
CT	Waterside	7-8	11 each	1964	38
CT	Cane Run	11	14	1968	34
CT	Paddy's Run	11	12	1968	34
CT	Paddy's Run	12	23	1968	34
CT	Zorn	1	14	1969	33
CT	Haefling	1,2,3	12 each	1970	32

Evaluation Scope

The evaluation of the Group 3 units has been broken up into a multi-phase approach due to the significant effort necessary to fully evaluate the economic viability of the Group 3 units. A detailed list of items and issues, the product of "brainstorming" exercises and the experiences gained from the Pineville 3 retirement, that should be considered when evaluating the economic viability of units was initially developed (see Appendix B-General Evaluation Outline for Phase II of Unit Viability Study). From this list the scope of Phase I was developed.

Phase I consists of a high level evaluation as a screening to identify the issues surrounding economic operation of the units. From this phase of the analysis, a determination will be made concerning the potential retirement of any or all of the units. The scope of the Phase I evaluation consists of the following:

1. Quantify and communicate the production cost impact (fuel cost, scrubber consumables cost, purchase power cost and SO_2/NO_x allowance cost) of retiring each unit in Group 3.
2. Quantify and communicate the capital cost impacts of the simultaneous retirement of all Group 3 units.
3. Identify fixed costs (environmental permitting/water usage costs, insurance premium impacts, depreciation expense etc) for each unit regardless of unit utilization.
4. Identify and discuss black-start units and the Companies' black-start obligations.
5. Discuss the unique contractual relationship LG&E has with the Louisville Water Company thru the Zorn combustion turbine.

Phase II of the Group 3 evaluation will follow upon completion of Phase I. The Phase II evaluation will consist of a detailed set of evaluations for each of the units identified in Phase I as being a potential for retirement. The initial scope of the Phase II evaluation will consist of the following:

1. Human Resource issues (severance pay, job reclassification, relocation).
2. Environmental issues (lead paint/asbestos abatement).
3. Intermediate-run options. (i.e. Evaluate costs of scenarios somewhere between current operations and retirement, utilization of Green River 1-2 FGD on another unit at Green River).
4. Unit "Re-powering" options (i.e. Tyrone 1-2).
5. Retirement Costs (stack demolition, scrubber/ash pond reclamation, etc.).

Financial Perspectives and Cases Evaluated

A financial analysis was performed from three different perspectives, a Regulated Company using a Revenue Requirements perspective, a Regulated Company using a Cash Flow determinant and finally, a Non-Regulated (or Merchant) Company evaluating each scenario via a Cash Flow perspective. Economic decisions regarding the regulated side of the business are normally conducted using a revenue requirements analysis, hence this was the primary evaluation technique used. A revenue requirements evaluation is based on the amount of money that must be collected by the Companies from the ratepayer to compensate the Companies for all capital and O&M expenditures (plus an allowed return on the Companies' capital investment) and taxes. The Regulated Company Cash Flow technique quantifies the decision from the vantage point of the regulated company shareholder. The final methodology represents how each decision would be viewed in a completely deregulated environment--from the perspective of an Independent Power Producer or Merchant entity. Merchant analyses are based on the option value (profit) each unit would have in the wholesale power market. Each scenario will be evaluated using each one of these three techniques.

Case Setup and Definition

- **Case 1**- Regulated Environment, Present Value Revenue Requirements
- **Case 2**- Regulated Environment, Present Value Cash Flow
- **Case 3**- Merchant Environment, Present Value Cash Flow

The annual cost streams resulting from each approach represent incremental costs or savings resulting from the retirement of the unit/units in question. It is important to keep in mind which Case is being evaluated when interpreting the revenue requirements or cash flow present values (PV) summaries. For example in Case 1, where a present value revenue requirements evaluation (PVRR) is being performed, a negative PVRR implies that the Company should collect less money from the ratepayers if the unit were to be retired. On the contrary, a positive PVRR, suggests the Company should collect more monies from the ratepayers to cover the increased cost of generation, purchase power, emissions expenses and so on. Stated another way, the presence of a negative

PVRR indicates that in present value, the cost savings obtained from retiring a unit outweighs the benefits of continued operation of said facility. The more negative a PVRR becomes, the stronger the argument for retiring that facility whereas the more positive a PVRR becomes the less economic justification that exists for retiring the unit.

Conversely, the Cash Flow values in Cases 2 and 3 work just the opposite. The more positive the Present Value of Cash Flow, the better the indication that retirement should occur. Hence, a negative PV Cash Flow would indicate a worse scenario results from retiring the unit, and thereby would support continued operation of the unit.

Global Base Assumptions

The following is a list of base assumptions applicable to all units evaluated in this study. Each unit may have additional issues that should be considered, and if so, those issues and a discussion of how they are addressed can be found in the appropriate section.

Global Assumptions

- 10 year evaluation period (2003-2012).
- Firm off-system sales volumes unchanged from 2002-2006 Corporate Business Plan. No firm sales beginning in 2007, however, hourly peak period opportunity sales exist thru end of evaluation period.
- Production cost impacts do not reflect obligation to maintain spinning reserve and are based on an expansion plan consisting of four simple-cycle CTs installed in 2004 and no coal unit in the 2008-2010 time frame. This was a conservative assumption from the plants perspective as the presence of a base-load coal unit would tend to further reduce the runtime and benefit of having these smaller units.
- Retirement in place can occur without any significant cost applicable to remaining physical plant unless otherwise noted.
- Retirement occurs January 1, 2003.
- Earnings Sharing Mechanism (ESM) impacts of retirement are negligible.
- Assume that 100% of the increased production costs are excluded from FAC (essentially assuming that any increased production related

expenses impact OSS margins) - applicable to Regulated Environment only.

- Purchase power available in 2003 around-the-clock at $100/MWh, escalating at 2%.

- Treatment of Capacity "Benefit" Dollars
  - In Revenue Requirements Analysis (Case 1), Capacity ($/kW) was an adder to the first years cost of replacement.
  - In Regulated Cash Flow Analysis (Case 2), Capacity ($/kW) is levelized.
  - In Merchant Cash Flow Analysis (Case 3), no Capacity ($/kW) benefit is given the retired unit since a Merchant plant is under no obligation to maintain any specific reliability, whether measured by reserve or capacity margin, or loss of load probability.

- Treatment of Capital Costs
  - In Revenue Requirements Analysis (Case 1), Capital dollars are levelized.
  - In Cash Flow Analysis (Case 2 and Case 3), Capital dollars are modeled as annual expenditures.

Black-Start Capability

This study has been performed exclusive of the cost of black-start capability on any of the units. Currently, the following units have black-start capability for the Companies: Haefling, Cane Run 11, Paddy's Run 11, Zorn 1, and the hydro units located at Dix Dam and Ohio Falls (however, the hydro stations are not considered part of the Group 3 units in this study). There is no current cost or value given to these units for having black-start capability. The issue of ECAR or NERC requirements regarding black-start is not being addressed in this Phase of the evaluation. Likewise, the Companies' needs/desires as they relate to black-start capability throughout the system are not being addressed here. Therefore, this study has only identified units with black-start capability and the economic evaluations have been performed exclusive of the appropriate units having a black-start monetary benefit.

Green River Units 1-2

The Green River Power Station is located off of US Highway 431 on the Green River in Muhlenberg County, Kentucky and is owned and operated by Kentucky Utilities Company, a subsidiary of LG&E Energy Corp. The plant was constructed during the late 1940s –1950s and houses four coal-fired generating units totaling 212MW (summer). The Green River supplies water to the plant.

Units 1 and 2 began commercial operation on March 1, 1950 and January 5, 1950 respectively. Units 1 and 2 consist of three interconnected B&W front wall-fired, non-reheat boilers rated at 215,000 lbs/hr steam capacity each, 875 psig, 910° F. These medium sulfur coal-fired boilers supply steam to two Westinghouse steam turbines summer rated at 22MW each and operating at 850 psig and 900° F. The cooling water system is a once-through type. In the 1970's a "scrubber" (FGD), currently operating with approximately 80% SO_2 removal efficiency, was constructed to service both Unit 1 and Unit 2. Coal is delivered to the station by truck. The units have Continuous Emission Monitoring (CEM) systems to monitor stack emissions. These units are operated with a capacity factor typically below 20%. There is an operations staff dedicated to these units. This evaluation estimates a staffing level of 9 employees for Units 1-2.

Green River Power Station
(Owned by Kentucky Utilities Company)

Green River 1-2 Base Assumptions

- Global Assumptions
- 2003-2006 Capital investment reflective of current Business Plan.
- Beginning in 2007, units will continue to reliably operate thru end of evaluation period with no significant capital investment.
- Non-Labor O&M cost thru 2006 as per plant management escalating at 2% in 2007 through the end of the period.
- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- Beneficial re-use of Unit's 1 and 2 FGD on Units 3 and 4 not evaluated.
- Units were assumed to be winterized during the period November thru April of the following year.
- Severance offered to 9 personnel at a total cost of under $100,000 due to the short tenure of the majority of personnel impacted personnel.
- Simultaneous retirement of Units 1-2 occur in 2003.
- Merchant Environment removes Production and SO_2/NO_x cost impacts as the effects of these are reflected in the option value profit.

In addition to a Base Scenario using the above assumptions, several additional scenarios were evaluated relative to Green River 1 and 2.

GR 1, 2 Scenario 1- Capacity benefit of $221/kW assigned (i.e. Capacity related cost incurred to replace retired unit's capability).

GR 1, 2 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

GR 1, 2 Scenario 3- Assume that some capital investment must be invested to insure reliable operation thru the end of evaluation period.

GR 1, 2 Scenario 4- Scenario 1 and Scenario 2 occur.

GR 1, 2 Scenario 5- Scenario 1 and Scenario 3 occur.

Table 3
Incremental Cost Impact of Retiring Green River Units 1, 2

Retire Green River Units 1 and 2	Case 1 Regulated Environment Present Value Revenue Requirements	Case 2 Regulated Environment Net Present Value Cash Flow Analysis	Case 3 Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($10,389,000)-R	$5,982,000-R	$3,010,000-R
Scenario 1- $221/kW Benefit	($680,000)-R	$775,000-R	Not Evaluated
Scenario 2- $1000/MWh Purch	($8,908,000)-R	$5,412,000-R	Not Evaluated
Scenario 3- Invest Capital $	($14,412,000)-R	$9,603,000-R	Not Evaluated
Scenario 4- Sce 1 & Sce 2	$802,000-O	$3,826,000-R	Not Evaluated
Scenario 5- Sce 1 & Sce 3	($4,702,000)-R	$4,396,000-R	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

All but one Scenario evaluated for Green River 1-2 suggests the units be retired. The Regulated Environment-Revenue Requirements analysis indicates that revenue requirements would be reduced in all but the most optimistic scenario by the retirement of Units 1 and 2 at Green River. The Revenue Requirements scenario that most strongly suggests retirement of these two facilities is Scenario 3 where capital expenditures equal to those originally proposed by plant management for the current budget period are deemed necessary expenses should the plant continue to operate and no capacity benefit is assigned to the units existing capacity. The Base Scenario also suggests that the two units should be retired even when the assumption is made that no capital expenses will be incurred thru the study period. The most beneficial Scenario, from the plant's perspective is Scenario 4 in which a $221/kW benefit is applied to replacement capacity in order to maintain the Company's 14% reserve margin and any market purchases resulting from the retirement of the Units cost $1000/MWh. This Scenario indicates that the revenue requirements of the Company would be increased by $802,000 (in present value) over the period if Green River Units 1-2 were to be retired.

The Regulated Environment-Cash Flow evaluation supports the retirement of Green River 1-2 as well. Each of the scenarios examined increases the Companies' cash flow. The Base Scenario, which assumes retirement occurs in 2003, indicates an increase in the Companies NPV cash flow of $5.9 million should no capacity value be assigned or $775,000 (Scenario 1) if the cost to replace Green River 1-2 capability is assumed to be $221/kW.

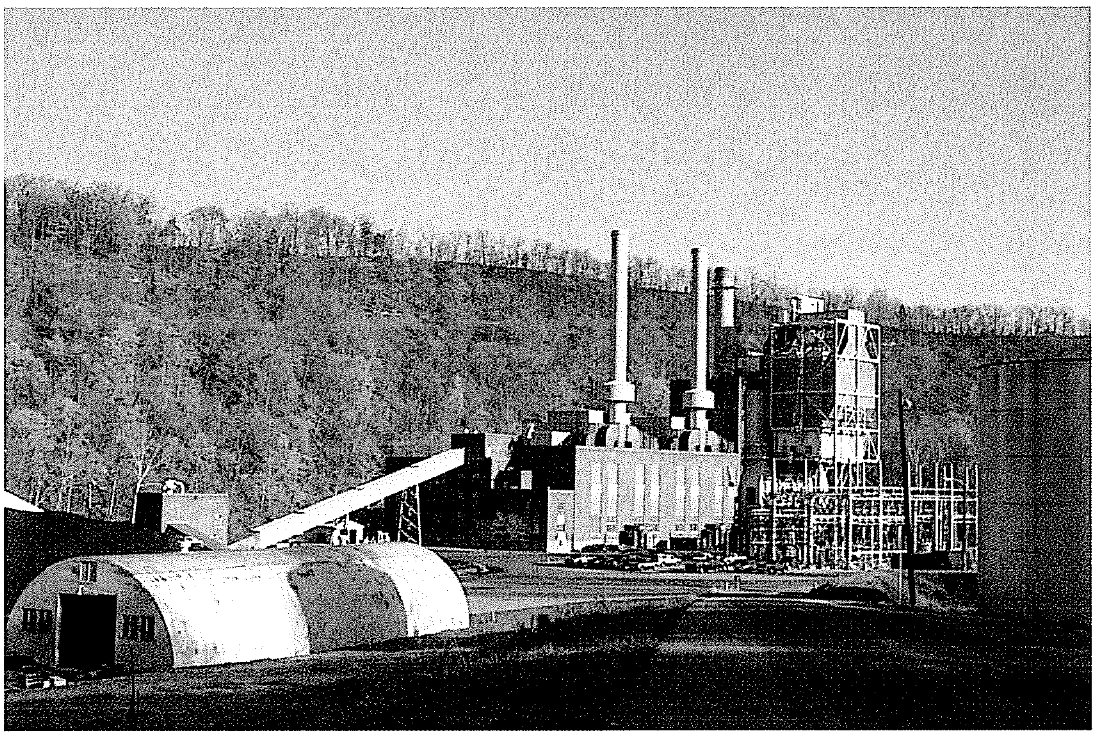
The Merchant Environment-Cash Flow perspective suggested retirement of Green River 1-2 as well. Very little option value can be justified for a steam unit with a high production cost and requiring a relatively long time-to-start. In addition depressed wholesale market prices and the reduced price volatility that often accompanies a soft market further exacerbate the economics of Green River 1-2 operation.

The dominating factors affecting the economics of Green River 1-2 are twofold. First there is the environmental cost impact of operation. While, the presence of a SO_2 scrubber on the units does reduce the SO_2 allowance cost impact, the units' high NO_x emission levels greatly detract from the economics of continued unit operation starting in 2004. With NO_x allowances on the order of $4000/ton and SO_2 allowances $150/ton it is estimated that retirement of Green River 1-2 will save over $5.8 million in NOx/SO2 allowance expenses. Second is the dedicated labor costs associated with operating and maintaining the units. While the $400,000 annual (loaded) labor cost estimates used has not been scrutinized for detailed accuracy it does reflect, within reason, the annual KU labor related cost associated with operation of Units 1 and 2.

In light of the cost associated with complying with NO_x environmental regulations and the potential O&M savings, Generation Services recommends that Green River Units 1 and 2 be in evaluated in Phase 2 of this study which will evaluate in detail costs associated with retirement of Green River Units 1 and 2.

Tyrone Units 1-2

The Tyrone Power Station is located on US Highway 62 at the Kentucky River in Woodford County, Kentucky and is owned and operated by Kentucky Utilities Company, a subsidiary of LG&E Energy Corp. The plant was constructed during the 1940s and houses three steam turbine generators totaling 129MW. The Kentucky River supplies water to the plant. Units 1 and 2 began commercial operation on October 12, 1947 and June 14, 1948 respectively. Presently contributing 27 and 31MW (summer ratings) to the KU/LG&E system, Units 1 and 2 have four interconnected B&W front wall fired, non-reheat boilers rated at 150,000 lbs/hr steam capacity each, 900 psig, 910° F. Originally coal fired, these boilers were converted to #2 fuel oil in 1971. Oil is delivered by truck and stored in an above ground tank. Unit 3, which burns low sulfur coal, uses the same oil for startup fuel and flame stabilization. These four boilers supply steam to two Westinghouse steam turbines rated at 25MW each operating at 850 psig and 900° F. The cooling water system is a once-through type. The units have CEM systems to monitor stack emissions and are primarily operated for peaking power during high system load periods. There are no employees solely dedicated to the operation and maintenance of these units. Employees primarily assigned to the operation of Unit 3 perform labor on these units through overtime.



Tyrone Power Station
(Owned by Kentucky Utilities Company)

Tyrone 1-2 Base Assumptions

- Global Assumptions

- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- Simultaneous retirement of Units 1-2 occur in 2003.
- Capital and O&M costs are not budgeted but reflect plant cost expectations to operate the units simultaneously for 1 full week in each of the summer months June, July and August.
- No staff impacts as a result of closing either Tyrone 1 or 2.
- Labor savings, if applicable, are in areas not currently budgeted.
- Labor O&M estimates represent overtime required by plant staff based on simultaneous runtimes (i.e. units 1 and 2 will always be operated together) for one full calendar week during each month of June, July and August.
- Capital costs reflect a runtime as assumed in Labor O&M for duration of evaluation period.
- Some retirement related costs for Tyrone 1-2 have been estimated by plant management and are included (Stack Dismantlement-$50,000; Mercury Removal-$20,000 and an annual Asbestos Containment expense -$5,000).
- Merchant Environment removes Production and SO_2/NO_x cost impacts as the effects of these are reflected in the option value profit.

In addition to a Base Scenario using the above assumptions, several additional scenarios were also evaluated.

TY 1, 2 Scenario 1- Capacity benefit of $221/kW assigned (i.e. Capacity related cost incurred to replace retired unit's capability).

TY 1, 2 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

TY 1, 2 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 4
Incremental Cost Impact of Retiring Tyrone Units 1, 2

Retire Tyrone Units 1 and 2	Case 1	Case 2	Case 3
	Regulated Environment Present Value Revenue Requirements	Regulated Environment Net Present Value Cash Flow Analysis	Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($1,430,000)-R	$872,000-R	$872,000-R
Scenario 1- $221/kW Benefit	$11,370,000-O	($5,982,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$1,512,000-O	($883,000)-O	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$14,311,000-O	($7,737,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

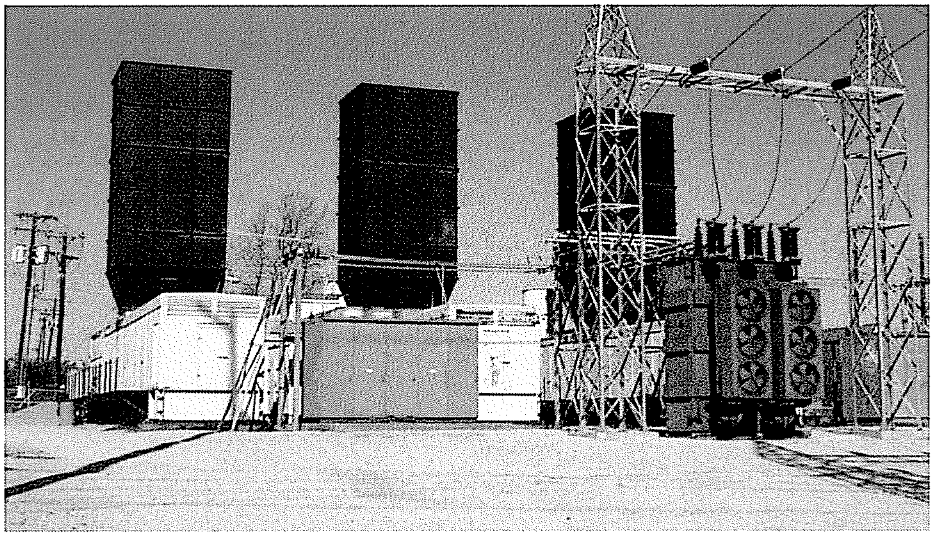
Each of the Base Scenarios in all three Cases suggests that retirement of Tyrone 1-2 would be economically sound. Retirement of the Units in the Base Scenario has the potential to reduce revenue requirements by a NPV of $1.4 million over the 10 year period. Revenue Requirements would increase (indicating that the economics favor continued operation) in all but the Base Scenario- where no capacity value is placed on the capability of Tyrone Units 1 and 2. It is of interest to note that the Case 1-Base Scenario break-even $/kW capacity benefit value for Tyrone 1-2 is approximately $25/kW. Therefore, if the assumed replacement cost of Tyrone 1-2 capacity is above $25/kW, then none of the Regulated Environment Scenarios evaluated would suggest retirement for Tyrone Units 1 and 2.

Evaluations of the Regulated and Merchant Cash Flow Base Scenarios arrive at the same conclusions as the Revenue Requirements analysis. Note that the Base Scenario of Case 2 and Case 3 yield the same dollar savings when the unit is retired. This is due to the fact that Tyrone 1-2 have no generation in any of the Base Scenarios. In the regulated environment Tyrone 1-2 are not utilized because their production costs exceed that of other units or purchase power and in the Merchant case it is out of the money based on current estimates of future market prices/volatility and the large lead-time (> 4 hours) associated with bringing a unit on line. Note however, that when either (or both) a $221/kW capacity value is assigned or high wholesale purchase power prices exist, the cash flow of the Company would be negatively impacted should the units be retired.

The economic evaluations of units such as Tyrone 1-2 are relatively straightforward. Given today's view that the depressed prices within the wholesale power market will not increase substantially in the near term and the fact that the units are not projected to run for native load or off-system sales (and hence have little or no opportunity to produce revenue) yet still incur fixed costs such as Insurance and Air/Water fees one should expect that the economics would favor unit retirement. That is exactly what the Base Scenarios indicate for Tyrone 1-2. Only when a $/kW capacity value (over $25/kW) is placed on Tyrone 1-2's capacity (regardless of whether the units are generating or not) or when purchase power must be bought from a $1000/MWh priced market do the economics favor the continued operation of these two units. Therefore, Generation Services recommends that the retirement of Tyrone Units 1 and 2 be evaluated in Phase 2 of this study.

Haefling Units 1, 2, 3

The Haefling Generating units are located off Baumann Drive in Lexington, Kentucky. There are three GE Frame 5 combustion turbines located within the Haefling Substation. These units burn natural gas or #2 fuel oil and are started by diesel engines. Each has a summer rated capacity of 12MW and is capable of providing black-start power for the E.W. Brown or Ghent Stations. All three units have undergone combustion chamber overhauls in the late 1990s; however, the control system is aging and reliability is decreasing. The inlet and exhaust plenums and silencers have been replaced allowing these units to continue to serve their peaking role. The site is not manned necessitating that Generation Dispatch notify Tyrone plant personnel when the Haefling Units are anticipated being dispatched. Tyrone plant personnel travel to Lexington (~45 minutes) to oversee the startup and operation of the units.



Haefling Power Station
(Owned by Kentucky Utilities Company)

Haefling 1-3 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- Simultaneous retirement of Units 1, 2 and 3 occur in 2003.
- Labor O&M estimates represent overtime required by 2 plant personnel for simultaneous runtimes on Unit 1-3 (i.e. units 1, 2 and 3 will always be operated together) for one full calendar week during each month of June, July and August.
- Capital costs reflect a runtime as assumed in Labor O&M for the duration of evaluation period.
- Capital expenditures consist of a $185,000 expenditure in 2004.
- No economic benefit for being a proven system black-start capable unit.
- Merchant Environment removes Production and SO2/NOx cost impacts as the effects of these are reflected in the option value profit.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

HF 1, 2, 3 Scenario 1- Capacity benefit of $221/kW assigned (i.e. Capacity related cost incurred to replace retired unit's capability).

HF 1, 2, 3 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

HF 1, 2, 3 Scenario 3 -Scenario 1 and Scenario 2 occur.

Table 5
Incremental Cost Impact of Retiring Haefling Units 1, 2, 3

Retire Haefling Units 1, 2 and 3	**Case 1** Regulated Environment Present Value Revenue Requirements	**Case 2** Regulated Environment Net Present Value Cash Flow Analysis	**Case 3** Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($293,000)-R	$217,000-R	($97,000)-O
Scenario 1- $221/kW Benefit	$7,651,000-O	($4,043,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$2,381,000-O	($1,377,000)-O	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$10,325,000-O	($5,638,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

From the Regulated-Revenue Requirements perspective the retirement of Haefling 1-3 would increase the Companies' revenue requirements (suggesting the facility not be retired) in all but the Base Scenario- where no replacement cost is placed on the capability of Haefling station. It is of interest to note that the break-even point for Case 1-Base Scenario is approximately $8/kW. Therefore, if the assumed value of Haefling 1-3 capacity is above $8/kW, then none of the Regulated Environment Scenarios evaluated would suggest retirement.

The Regulated Environment Cash Flow Analysis arrives at the same conclusions as the Regulated Environment Revenue Requirements. When either a $221/kW capacity value is assigned and/or high wholesale power prices exist, the cash flow of the Company would be negatively impacted.

In contrast to the Revenue Requirements analysis and the Regulated Environment Cash Flow analysis, the Merchant Environment Cash Flow Analysis does not suggest that closure of the Haefling station. Given the current wholesale market volatility and prices, the closure of Haefling would negatively impact, although modestly, the cash flows of the Company ($97,000 in present value of the ten year period). One significant factor impacting the economics is that more than $1 million presently estimated to be on the books would have to be written off if Haefling were to be retired.

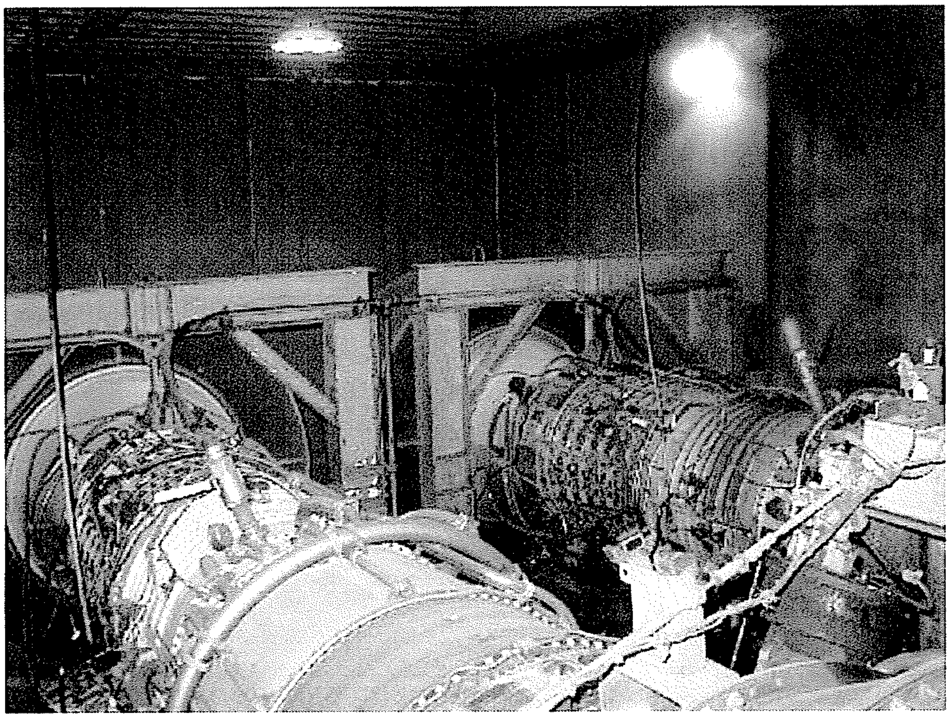
There appears to be some reasonable scenarios in which the retirement of Haefling is warranted and as such, it is recommended that the retirement of Haefling be evaluated in Phase 2 of this study.

Waterside Units 7-8

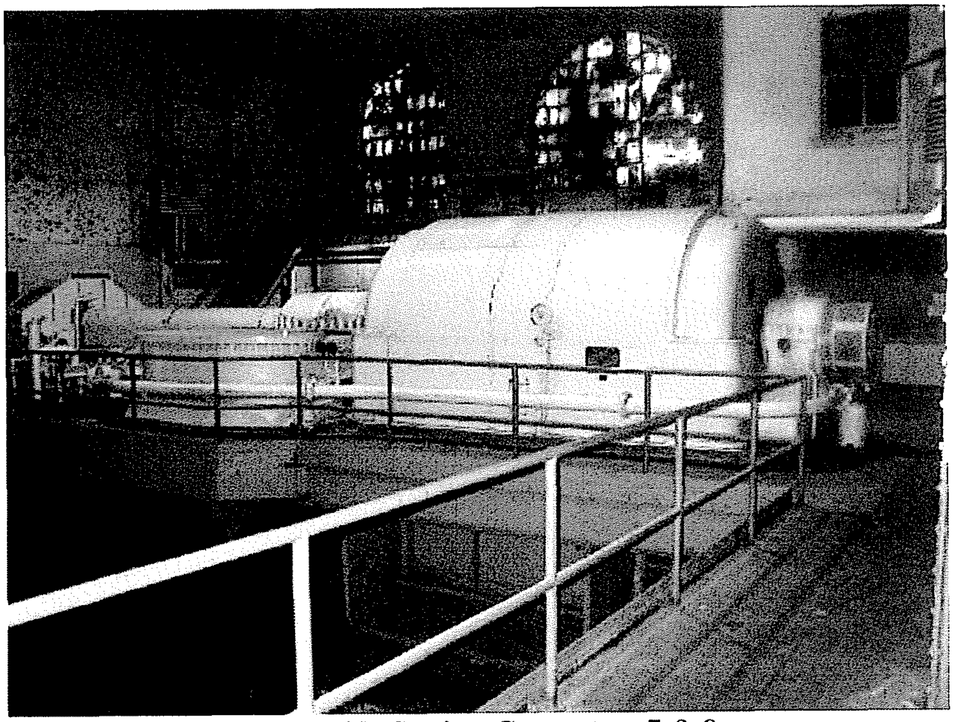
The site is located in a former coal-fired power station in downtown Louisville, Kentucky. Each generating unit consists of two GE 7LM1500-PD101 industrial aero derivative gas turbines, which operate at 5523 rpm. Both units drive through a common load gear to the original 1920's 20MW generators, which run at 1800 rpm. A fuel gas compressor is located outside the main building in a dedicated enclosure. The units do not provide a black-start capability and were commissioned in 1964. The summer rated net capability of each is 11MW. The units are started locally and the site is manned during operation, typically during peak load periods.

Unit 8 had both gas generators, replaced in 1999 following the failure of a turbine blade that damaged both the gas generator and power turbine (8B). The original gas generators (CJ805) were obsolete and were replaced with a later refurbished model (J79).

Other than to replace unit 8's gas generators there have been no other major overhauls, inspections or repairs to either turbine generating set. The gas compressor was overhauled in 1996 and is working reliably; however, it is now obsolete and parts are difficult to obtain. There are a number of issues and concerns with both units, which would require significant investment to rectify and as a result it is difficult to justify the full capacity benefit used previously in this evaluation of $221/kW without a substantial amount of work/inspection being conducted on the machines. Evaluation of these units with the full $221/kW value is only justified if the machines were to undergo a Control System upgrade and a Hot Gas Path Inspection (HGPI) and part replacement. A scenario was evaluated that regards the units as having the necessary capital and O&M expenditures to justify the full $221/kW capacity benefit.



Waterside Station-Units 7 & 8
(Owned by Louisville Gas and Electric Company)



Waterside Station-Generators 7 & 8
(Owned by Louisville Gas and Electric Company)

Waterside 7-8 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- No Capital expenditures and no significant non-labor O&M is required through the study period to maintain "status-quo" operational characteristics (start reliability, availability etc).
- Waterside 7 and 8 are not black-start capable.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

WS 7, 8 Scenario 1- Capacity benefit increased to $221/kW thru a needed $1.25 million (per unit) maintenance expense consisting of a control system upgrade and a Hot Gas Path Inspection (HGPI) and part replacement (as needed) occurring in 2006.

WS 7, 8 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

WS 7, 8 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 6
Incremental Cost Impact of Retiring Waterside Units 7, 8

Retire Waterside Units 7 and 8	**Case 1** Regulated Environment Present Value Revenue Requirements	**Case 2** Regulated Environment Net Present Value Cash Flow Analysis	**Case 3** Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($58,000)-R	$134,000-R	($342,000)-O
Scenario 1- $221/kW Benefit + Increased Maintenance Costs	$2,409,000-O	($5,290,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$48,000-O	$71,000-R	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$2,515,000-O	$2,102,000-R	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

The Base Scenarios for two of the three Cases indicate retirement of Waterside 7-8 would be prudent. Waterside Units 7-8, like Tyrone Units 1-2 do not generate in the Regulated environment Base Scenarios (Case 1 and Case 2). The units fixed costs of operation (Insurance, Non-Labor O&M etc) therefore are not able to be offset by any revenues except a capacity benefit. When a capacity benefit is applied, the economics suggest continued operation to be marginally economically favorable. One point of interest is that the break-even $/kW capacity benefit for Case 1- Scenario 1 is $111/kW (Note: It would be incorrect to calculate a breakeven $/kW cost on Case 1- Base Scenario because the units should be subject to a HGPI, the costs of which are included only in Scenarios 1 and 3).

In light of the economic evaluation performed above, Generation Services recommends that the retirement of Waterside Units 7-8 be further evaluated in Phase II of this study.

Paddy's Run 11-12

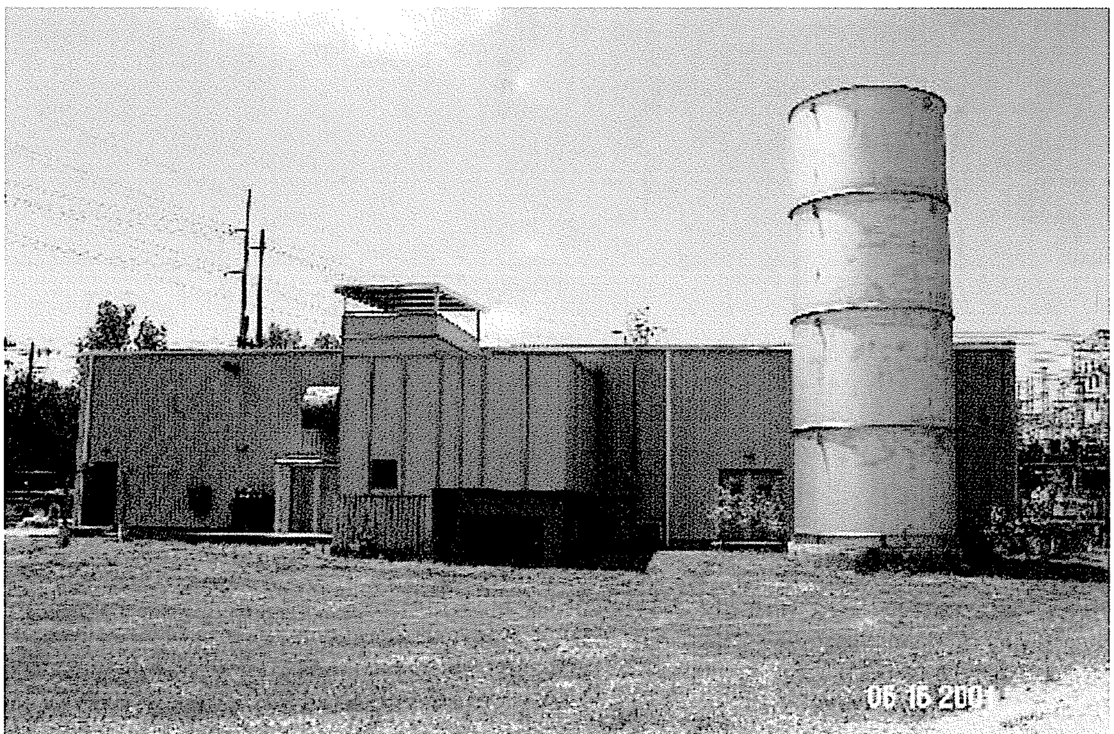
Unit 11 is a 12MW (net summer rating) GE Frame 5001LA gas turbine located in a close fitting acoustic enclosure adjacent the switchyard of the retired Paddy's Run coal-fired power station in Louisville, Kentucky. Although the coal-fired power station is closed the switchyard and substations remain active. The unit is normally started locally although remote starting is possible from the LG&E load dispatch office in downtown Louisville. The unit operates on gas fuel only and commenced operation on June 10, 1968.

Unit 11 is generally in good and serviceable condition with the gas turbine and load gear being overhauled in 1996, although the generator was not inspected. The unit has started reliably and provides black-start capability. The main risk to the continued good reliability is that the control system is now obsolete and there is increasing difficulty finding support and spare parts.

Paddy's Run Unit 11
(Owned by Louisville Gas and Electric Company)

Unit 12 is located within a single, portal frame metal clad building adjacent the switchyard of the closed Paddy's Run coal-fired power station in Louisville, Kentucky. Unit 12 is a Westinghouse 301G gas turbine generator. This is a long, heavy-duty industrial gas turbine featuring cold end drive, two-bearing configuration, can-annular combustion and a hydrogen-cooled generator. The gas turbine operates at 3600 rpm and therefore requires no load gear. First operated on July 16, 1968, Paddy's Run 12 operates on gas fuel only and has a net summer rating of 23MW.

Unit 12 is currently started locally, although remote starting has been installed but is not fully implemented. The unit requires significant investment to overhaul the gas turbine and generator and to upgrade its control. As a result, starting reliability is poor. Two to three days annually is normally spent testing systems and preparing the unit for operation and even then the unit often fails to achieve load. The unit does not contribute any black-start capability to the system.



Paddy's Run Unit 12
(Owned by Louisville Gas and Electric Company)

Paddy's Run 11-12 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- Base Capital expenditures are $250,000 in 2004 for Unit 11 and $350,000 ($100,000 in 2003, $250,000 in 2005) for Unit 12.
- No economic benefit for Unit 11 being a proven system black-start capable unit.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

PR 11, 12 Scenario 1- Capacity benefit increased to $221/kW as a result of additional capital expenses of $1 million for a Hot Gas Path Inspection (HGPI) and part replacement on Unit 11 (in 2004), and $1 million HGPI/part replacement on Unit 12 in 2005.

PR 11, 12 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

PR 11, 12 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 7
Incremental Cost Impact of Retiring Paddy's Run Units 11, 12

Retire Paddy's Run 11-12	**Case 1**	**Case 2**	**Case 3**
	Regulated Environment Present Value Revenue Requirements	Regulated Environment Net Present Value Cash Flow Analysis	Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($979,000)-R	$742,000-R	$101,000-R
Scenario 1- $221/kW Benefit + Increased Maintenance Cost	$4,182,000-O	($1,385,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$63,000-O	$120,000-R	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$5,224,000-O	($2,007,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

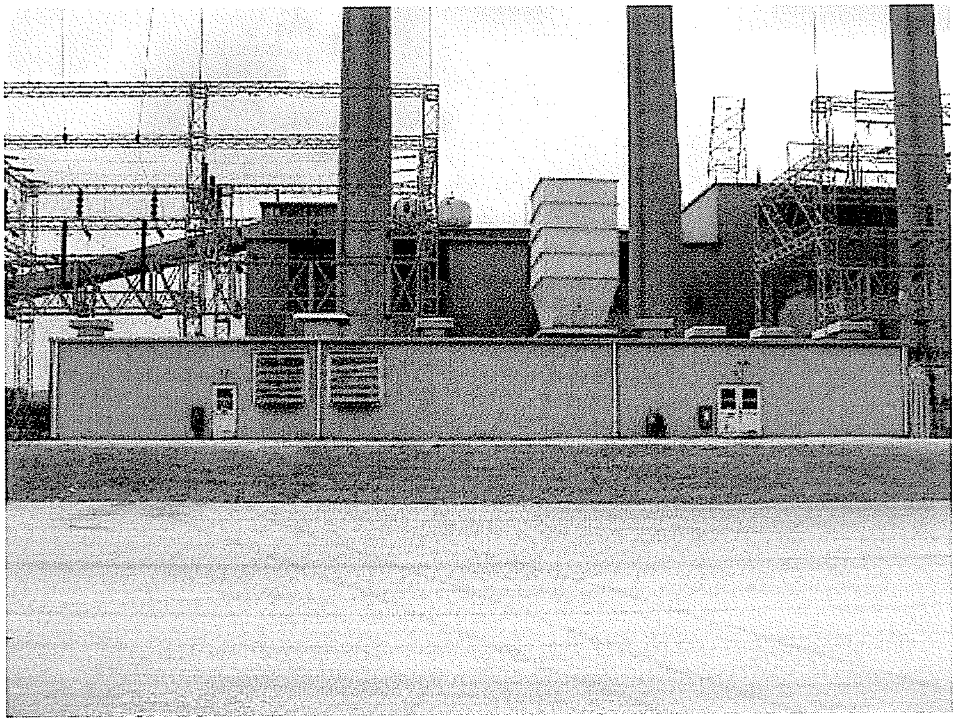
Results of all Base Scenarios for Paddy's Run 11 and 12 imply that the units should be retired. The economics of Paddy's Run 11 and 12, like the Waterside Units, justify continued operation in only one of the two scenarios when the purchase power price is $1000/MWh (Case 1 Scenario 2). With a capacity benefit of $221/kW in spite of the $2 million costs to perform a HGPI, the economics suggest continued operation to be economically favorable. One point of interest is that the break-even $/kW capacity benefit for Case 1- Scenario 1 is $101/kW (Note: It would be incorrect to calculate a breakeven $/kW cost on Case 1- Base Scenario because the units should be subject to a HGPI, the costs of which are included only in Scenarios 1 and 3).

In light of the economic evaluation performed above, Generation Services recommends that the retirement of Paddy's Run Units 11, 12 be further evaluated in Phase II of this study.

Cane Run 11

Cane Run 11 is located on the site of the Cane Run coal-fired station in Louisville, Kentucky. The unit is a Westinghouse W191G gas turbine installed inside a portal frame clad building. The unit is a heavy-duty industrial gas turbine featuring cold end drive, two-bearing configuration, can-annular combustion and an air-cooled generator. With a net summer capability of 14MW it is the only LG&E peaking unit that has dual fuel capability. The unit commenced operation on April 29, 1968.

The gas turbine is in good and serviceable condition having been overhauled in the spring of 2000. The load gear and generator were inspected and found to be in good condition. The main risk to the continued good reliability is that the control system is now obsolete and there is increasing difficulty finding support and spare parts. The unit is normally started locally although remote control is available in a nearby switchyard control room. The unit has black-start capabilities.



Cane Run Unit 11
(Owned by Louisville Gas and Electric Company)

Cane Run 11 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity related cost incurred to replace retired unit's capability.
- Base Capital expenditures are $250,000 in 2003 associated with a controls upgrade.
- No economic benefit for being proven system black-start capable.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

CR11 Scenario 1- Capacity benefit increased to $221/kW. This unit had an overhaul performed in the spring of 2000.

CR11 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

CR11 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 8
Incremental Cost Impact of Retiring Cane Run Unit 11

Retire Cane Run 11	Case 1	Case 2	Case 3
	Regulated Environment Present Value Revenue Requirements	Regulated Environment Net Present Value Cash Flow Analysis	Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($208,000)-R	$214,000-R	$27,000-R
Scenario 1- $221/kW Benefit	$2,881,000-O	($1,442,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	($48,000)-R	$119,000-R	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$3,042,000-O	($1,538,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

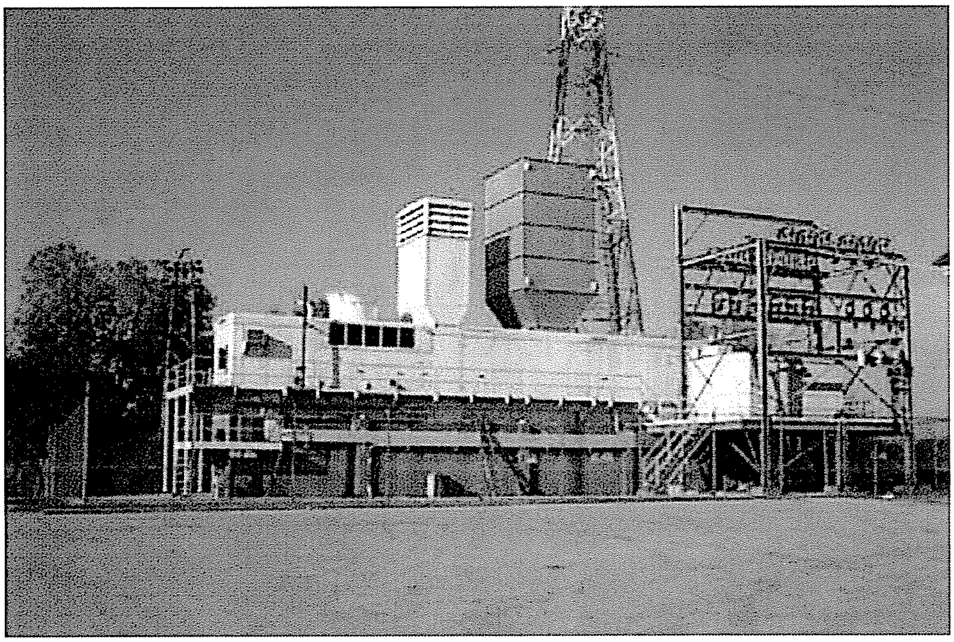
Results of all Base Scenarios for Cane Run 11 once again indicate that the units should be retired. The economics of continued operation are unfavorable to the units even when the purchase power price is $1000/MWh . When a capacity benefit of $221/kW is factored in, the economics suggest continued operation to be economically favorable. One point of interest is that the break-even $/kW capacity benefit for Case 1- Base Scenario is $15/kW.

In light of the economic evaluation performed above, Generation Services recommends that the retirement of Cane Run Unit 11 be further evaluated in Phase II of this study.

Zorn 1

The Zorn gas turbine generating unit is a GE Frame 5001 LA installed in a close-fitting acoustic enclosure. The unit is located in a small fenced enclosure adjacent to the Louisville Water Companies' (Water Company) river water pumping station and sits on a tall concrete base to protect it against flooding. The unit was installed primarily to supply emergency power for the nearby Riverside pumping station. A contract exists between the Water Company and LG&E. More information on the LG&E/Water Company contract can be found in the section titled LG&E, Louisville Water Company and Zorn CT. The Water Company makes annual payments of $10,000 to LG&E associated with that contract. The unit operates on gas fuel only and has a net summer rating of 14MW. The unit commenced operation on the May 23, 1969.

The unit is in good and serviceable condition. The gas turbine and load gear (but not the generator) had a major inspection and overhaul in 1995. Remote starting, although possible, is problematic; therefore the unit is normally started locally. The unit has started reliably and has black-start capability. The main risk to the continued good reliability is that the control system is now obsolete and there is increasing difficulty finding support and maintenance spare parts.



Zorn Unit 1
(Owned by Louisville Gas and Electric Company)

Zorn 1 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity related cost incurred to replace retired unit's capability.
- Base Capital expenditures expected to be $250,000 in 2004 associated with a controls upgrade.

- While this unit is a proven system black-start unit, it is under contract to service the Louisville Water Company during a black-start emergency. No economic benefit is assumed.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

ZN 1 Scenario 1- Capacity benefit increased to $221/kW as a result of additional capital expenditure of $1 million for a Hot Gas Path Inspection (HGPI) and part replacement in 2004.

ZN 1 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

ZN 1 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 9
Incremental Cost Impact of Retiring Zorn Unit 1

Retire Zorn 1	**Case 1** Regulated Environment Present Value Revenue Requirements	**Case 2** Regulated Environment Net Present Value Cash Flow Analysis	**Case 3** Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($327,000)-R	$295,000-R	$4,000-R
Scenario 1- $221/kW Benefit + Increased Maintenance Cost	$1,394,000-O	($317,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$123,000-O	$26,000-R	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$1,843,000-O	($585,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

Retirement of Zorn Unit 1 is the suggested course of actions based on the results of all three Base Scenarios. The unit is also uneconomical to continue to operate under one of the two Cases of Scenario 2, where the price of purchase power is $1000/MWh. The production cost of this unit are generally the highest of any LG&E unit and the resulting limited run time the unit normally is experiences is not sufficient, in this analysis, to produce enough benefits to cover the annual expenses of depreciation, insurance etc. As with the other Group 3 units, addition of a capacity adder suggests the unit should continue to operate. One point of interest is that the break-even $/kW capacity benefit for Case 1- Base Scenario is $121/kW.

Based on the results of this evaluation, Generation Services recommends that retirement of the Zorn CT be evaluated in Phase II of this analysis.

LG&E, Louisville Water Company and Zorn CT

LG&E has a special contract with the Louisville Water Company for emergency power from the Zorn CT. The contract was entered into on November 25, 1968 and renews annually unless cancelled by either party. The contract requires the parties give 2 year notice to terminate. The Water Company has paid LG&E $40,000 per year from 1969-1993 to maintain the unit and for capital recovery. From 1994 until the contract is cancelled, the Water Company will pay $10,000 per year for maintenance and for capital recovery. Other than showing the $10,000 annual payment stream that would go away if Zorn would be retired, this evaluation only recognizes that contractual obligations exist and does not factor any other costs stemming from the contract into the financial analysis.

Conclusion and Recommendation

KU and LG&E have several units currently in service that warrant close examination of the costs associated with keeping them in service compared to the costs of retiring the facility. The age and operational cost of the thirteen units identified in Group 3 suggest that it may be the best economic decision to retire these units. This Phase I evaluation took a high-level view of each unit and evaluated the 10 year cost streams incurred from both operating that unit and the costs incurred if the unit were to be retired. Present value revenue requirements and present value cash flow techniques were performed for a base scenario and various sensitivity scenarios. The base scenario for all units under all financial techniques utilized indicated that possible cost savings could be realized if the units were to be retired in place. The analysis was highly sensitive to the value put on the capacity benefit of the units in contributing to the Companies' reserve margin obligation. Sensitivities were performed around this capacity value with Green

River 1-2 being the only units that continued to suggest the retirement of the units would be the best economic option. It is therefore recommended that all 13 units continue to be evaluated in Phase II for possible retirement.

Appendix A
Service Hours by Unit
(1993-2002)

Service Hours by Unit

GROUP	UNIT	Service Hours (Run-Times) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Group 1	BR3	5,791	7,428	4,845	7,750	6,636	7,324	7,986	8,265	7,519	7,105
	GH1	7,847	5,984	7,838	8,046	7,392	7,479	7,820	6,884	7,957	7,199
	GH2	7,554	8,078	8,302	7,402	8,082	7,917	7,906	7,263	7,679	7,533
	GH3	7,858	7,928	7,277	8,545	7,934	7,576	7,847	8,137	7,882	8,112
	GH4	6,233	8,107	8,488	7,526	7,869	8,255	7,810	8,413	8,337	5,922
	MC1	6,523	6,788	7,024	6,650	7,317	6,742	7,769	7,483	7,281	7,112
	MC2	6,591	6,975	6,376	7,253	6,807	6,301	7,913	8,029	7,219	7,671
	MC3	6,880	7,769	6,041	7,370	7,715	7,392	6,747	7,447	7,929	7,022
	MC4	7,273	5,678	7,352	8,018	6,193	7,075	5,911	7,189	6,282	7,170
	TC1	7,608	7,713	7,618	6,962	8,213	7,547	8,372	7,483	7,108	7,883
	BR5									491	809
	BR6								269	74	814
	BR7								260	457	665
	BR8				57	137	670	508	581	609	474
	BR9				40	39	702	433	443	380	277
	BR10				36	199	676	417	395	238	287
	BR11				17	74	399	435	254	153	177
	PR13									333	794
	TC5										737
	TC6										719
Group 2	BR1	6,555	6,065	4,953	6,502	6,747	7,046	6,587	7,984	8,077	8,128
	BR2	6,831	5,419	6,158	6,859	7,511	7,867	7,796	7,130	6,426	6,969
	CR4	5,373	7,023	7,124	5,563	8,022	7,407	6,862	7,877	7,460	8,082
	CR5	6,559	5,919	6,080	6,416	6,751	6,839	7,766	6,747	6,982	7,593
	CR6	6,654	5,026	5,290	6,738	6,681	6,852	6,234	7,250	7,188	5,134
	GR3	4,353	5,554	6,328	5,495	3,830	6,598	7,382	7,165	6,797	4,133
	GR4	6,896	6,641	4,594	4,540	6,785	7,700	6,805	7,281	7,055	6,657
	TY3	2,324	2,161	2,791	2,492	2,818	4,300	4,504	5,956	5,831	5,586
Group 3	CR11	29	64	78	135	185	176	119	29	31	14
	GR1	425	46	550	176	197	2,091	1,368	2,980	1,991	1,692
	GR2	452	130	610	124	254	2,268	1,416	3,130	1,995	1,674
	HF1	1	1	36	17	1	205	126	33	5	2
	HF2	1	1	36	26	2	169	138	29	1	2
	HF3	1	1	31	16	2	208	134	26	6	2
	PR11	4	0	0	36	236	258	194	69	18	5
	PR12	13	45	140	111	201	267	184	63	16	7
	TY1	162	7	373	4	40	115	76	0	18	0
	TY2	45	105	372	58	24	131	181	0	17	0
	WS7	27	31	75	8	133	245	138	57	6	2
	WS8	27	31	0	6	42	15	19	41	5	2
	Z1	9	0	96	117	210	194	160	57	23	4

Note:

The data for Group 1 excludes the service hours associated with Dix Dam and Ohio Falls hydro units.

Appendix B
General Evaluation Outline for Phase II of Unit Viability Study

General Evaluation Outline for Phase II of Unit Viability Study

I) **General Unit Data** (Generation Planning, Generation Engineering, Plant Staff)
   a) Unit Name
   b) In-Service Year
   c) Boiler Data
   d) Turbine Data
   e) Generator Data
   f) GSU Data

II) **Operating Data** (Generation Planning, Generation Engineering, Plant Staff)
   a) Annual Net Generation
      i) Seasonal Generation
   b) Annual Net Summer/Winter Capacity
   c) Annual GADS Data
      i) EFOR
      ii) MOH
      iii) FOR
   d) Maintenance
      i) Historical/Scheduled Turbine/Generator Overhaul
      ii) Historical/Scheduled Annual Maintenance Weeks

III) **Plant/Unit Assessment** (Generation Engineering)
   a) Risks of continued operation
   b) Impact on other units at the site
   c) Impact on the system

IV) **O&M costs** (Plant Staff, Generation Planning, Generation Engineering)
   a) Operational costs
   b) Maintenance costs
      i) Routine maintenance
      ii) Overhauls
   c) Capital Projects

V) **Layup Vs Retire** (Generation Planning, Operations Analysis, Generation Engineering)
   a) Operational costs
   b) Maintenance costs
   c) Staffing

VI) **Capacity and Energy Value** (Generation Planning, Market Valuation)
   a) Impact on expansion plan or reserve margin
   b) Market value of capacity and energy

VII) **Environmental** (Environmental Affairs, Generation Planning, Generation Engineering)
- a) Ash Pond
- b) SO_2 Emissions
  - i) Rate (#/mmbtu)
  - ii) Annual Tons
- c) NO_x Emissions
  - i) Ozone Season
    - (1) Rate (#/mmbtu)
    - (2) Annual/Monthly Tons
- d) Mercury Emissions
- e) Asbestos
- f) Lead based paint
- g) PCB
- h) Coal yard reclamation
- i) Chemical disposal
- j) UST closure
- k) Permit modification(s)/notification(s)(DOW, DWM, DAQ, State Boiler Inspector)

VIII) **Scrap/Salvage/Re-Use Potential** (Plant Staff, Generation Engineering, Generation Planning)
- a) Scrap Value – raw material value
- b) Salvage Value – equipment with potential resale value
- c) Identify location of identical turbines still in operation for possible purchase of balance of plant equipment or strategic spares
- d) Opportunities exist to use GSU or BOP equipment on other units within KU/LG&E or at another company.

IX) **KY Public Service Commission** (Regulatory Management, Generation Planning)
- a) Any required filings
- b) Effect on ECR
- c) Effect on ESM

X) **Financial** (Operations Analysis, Property Accounting)
- a) Current Book Cost
- b) Depreciation related expenses
- c) Are stranded costs an issue

XI) **Community Issues** (Corporate Communications, External Affairs)
- a) Public Comments/Affected Community Meetings
- b) Relationship with the Louisville Water Company (Zorn unit)

XII) **Transmission System Issues** (Transmission Planning & Substations)
- a) Voltage Support: Affect of unit retirements on area voltage support.
- b) Substation reliability (remote operation of equipment)

XIII) **Fuel** (Fuels Management)

a) Contract termination issues
b) For Haefling, what would happen to gas line.

XIV) **Employees** (Human Resources)

a) Number of Union Employees
b) Number of Non-Union Employees
c) Options for redeployment/ retirement

Appendix C
Revenue Requirements Financial Analysis
(Case 1)

Retire Green River Units 1-2
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market, No Capital Budget)												
Production	$ 249	$ 16	$ -	$ -	$ -	$ -	$ 60	$ -	$ -	$ -	$ 300	
SO2/NOx	$ 52	$ (632)	$ (1,015)	$ (1,199)	$ (936)	$ (846)	$ (848)	$ (1,387)	$ (946)	$ (1,046)	$ (5,806)	
Insurance	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (467)	
Air/Water Fees	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (141)	
Labor O&M	$ (451)	$ (460)	$ (469)	$ (479)	$ (488)	$ (498)	$ (508)	$ (518)	$ (528)	$ (539)	$ (3,439)	
Non-Labor O&M	$ (75)	$ (300)	$ (300)	$ (150)	$ (153)	$ (156)	$ (159)	$ (162)	$ (166)	$ (169)	$ (1,284)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 2,365	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ 332	
Severance	$ 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	
Total	$ 2,169	$ (1,797)	$ (2,206)	$ (2,249)	$ (1,999)	$ (1,921)	$ (1,877)	$ (2,489)	$ (2,062)	$ (2,175)	$ (10,389)	Retire
Scenario 1 (221 $/kw Capacity Benefit)												
Production	$ 249	$ 16	$ -	$ -	$ -	$ -	$ 60	$ -	$ -	$ -	$ 300	
SO2/NOx	$ 52	$ (632)	$ (1,015)	$ (1,199)	$ (936)	$ (846)	$ (848)	$ (1,387)	$ (946)	$ (1,046)	$ (5,806)	
Insurance	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (467)	
Air/Water Fees	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (141)	
Labor O&M	$ (451)	$ (460)	$ (469)	$ (479)	$ (488)	$ (498)	$ (508)	$ (518)	$ (528)	$ (539)	$ (3,439)	
Non-Labor O&M	$ (75)	$ (300)	$ (300)	$ (150)	$ (153)	$ (156)	$ (159)	$ (162)	$ (166)	$ (169)	$ (1,284)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	
Capacity Benefit	$ 9,710	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,710	
Write off/Depreciation	$ 2,365	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ 332	
Severance	$ 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	
Total	$ 11,879	$ (1,797)	$ (2,206)	$ (2,249)	$ (1,999)	$ (1,921)	$ (1,877)	$ (2,489)	$ (2,062)	$ (2,175)	$ (680)	Retire
Scenario 2 (1000 $/MWh Purchase Market Price)												
Production	$ 1,281	$ 459	$ -	$ -	$ -	$ -	$ 60	$ -	$ -	$ -	$ 1,739	
SO2/NOx	$ 56	$ (623)	$ (1,010)	$ (1,199)	$ (929)	$ (847)	$ (848)	$ (1,387)	$ (946)	$ (1,000)	$ (5,763)	
Insurance	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (467)	
Air/Water Fees	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (141)	
Labor O&M	$ (451)	$ (460)	$ (469)	$ (479)	$ (488)	$ (498)	$ (508)	$ (518)	$ (528)	$ (539)	$ (3,439)	
Non-Labor O&M	$ (75)	$ (300)	$ (300)	$ (150)	$ (153)	$ (156)	$ (159)	$ (162)	$ (166)	$ (169)	$ (1,284)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 2,365	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ 332	
Severance	$ 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	
Total	$ 3,205	$ (1,346)	$ (2,201)	$ (2,249)	$ (1,991)	$ (1,923)	$ (1,877)	$ (2,489)	$ (2,062)	$ (2,130)	$ (8,908)	Retire
Scenario 3 (Assume Capital $ Investment for Reliable Operation)												
Production	$ 249	$ 16	$ -	$ -	$ -	$ -	$ 60	$ -	$ -	$ -	$ 300	
SO2/NOx	$ 52	$ (632)	$ (1,015)	$ (1,199)	$ (936)	$ (846)	$ (848)	$ (1,387)	$ (946)	$ (1,046)	$ (5,806)	
Insurance	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (467)	
Air/Water Fees	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (141)	
Labor O&M	$ (451)	$ (460)	$ (469)	$ (479)	$ (488)	$ (498)	$ (508)	$ (518)	$ (528)	$ (539)	$ (3,439)	
Non-Labor O&M	$ (75)	$ (300)	$ (300)	$ (150)	$ (153)	$ (156)	$ (159)	$ (162)	$ (166)	$ (169)	$ (1,284)	
Levelized Capital	$ (142)	$ (265)	$ (648)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (4,023)	
Asset Retire Cost	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 2,365	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ 332	
Severance	$ 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	
Total	$ 2,027	$ (2,062)	$ (2,854)	$ (2,968)	$ (2,718)	$ (2,641)	$ (2,597)	$ (3,209)	$ (2,781)	$ (2,895)	$ (14,412)	Retire

Retire Green River Units 1-2
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Scenario 4 (Scenario 1 and Scenario 2 Occur)												
Production	$ 1,281	$ 459	$ -	$ -	$ -	$ -	$ 60	$ -	$ -	$ -	$ 1,739	
SO2/NOx	$ 56	$ (623)	$ (1,010)	$ (1,199)	$ (929)	$ (847)	$ (848)	$ (1,387)	$ (946)	$ (1,000)	$ (5,763)	
Insurance	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (467)	
Air/Water Fees	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (141)	
Labor O&M	$ (451)	$ (460)	$ (469)	$ (479)	$ (488)	$ (498)	$ (508)	$ (518)	$ (528)	$ (539)	$ (3,439)	
Non-Labor O&M	$ (75)	$ (300)	$ (300)	$ (150)	$ (153)	$ (156)	$ (159)	$ (162)	$ (166)	$ (169)	$ (1,284)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	
Capacity Benefit	$ 9,710	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,710	
Write off/Depreciation	$ 2,365	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ 332	
Severance	$ 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	
Total	$ 12,915	$ (1,346)	$ (2,201)	$ (2,249)	$ (1,991)	$ (1,923)	$ (1,877)	$ (2,489)	$ (2,062)	$ (2,130)	$ 802	Operate
Scenario 5 (Scenario 1 and Scenario 3 Occur)												
Production	$ 249	$ 16	$ -	$ -	$ -	$ -	$ 60	$ -	$ -	$ -	$ 300	
SO2/NOx	$ 52	$ (632)	$ (1,015)	$ (1,199)	$ (936)	$ (846)	$ (848)	$ (1,387)	$ (946)	$ (1,046)	$ (5,806)	
Insurance	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (467)	
Air/Water Fees	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (141)	
Labor O&M	$ (451)	$ (460)	$ (469)	$ (479)	$ (488)	$ (498)	$ (508)	$ (518)	$ (528)	$ (539)	$ (3,439)	
Non-Labor O&M	$ (75)	$ (300)	$ (300)	$ (150)	$ (153)	$ (156)	$ (159)	$ (162)	$ (166)	$ (169)	$ (1,284)	
Levelized Capital	$ (142)	$ (265)	$ (648)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (4,023)	
Asset Retire Cost	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	
Capacity Benefit	$ 9,710	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,710	
Write off/Depreciation	$ 2,365	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ 332	
Severance	$ 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	
Total	$ 11,737	$ (2,062)	$ (2,854)	$ (2,968)	$ (2,718)	$ (2,641)	$ (2,597)	$ (3,209)	$ (2,781)	$ (2,895)	$ (4,702)	Retire

Retire Tyrone Units 1-2
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)												
Production	$ 0	$ -	$ 0	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ 0	
SO2/NOx	$ (0)	$ (0)	$ -	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ (0)	$ (0)	
Insurance	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (279)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)	
Labor O&M	$ (125)	$ (125)	$ (125)	$ (127)	$ (130)	$ (133)	$ (135)	$ (138)	$ (141)	$ (143)	$ (922)	
Non-Labor O&M	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (41)	$ (42)	$ (42)	$ (43)	$ (287)	
Levelized Capital	$ -	$ -	$ -	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (43)	
Asset Retire Cost	$ 75	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 105	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ (130)	$ (200)	$ (200)	$ (213)	$ (215)	$ (218)	$ (221)	$ (225)	$ (228)	$ (232)	$ (1,430)	Retire
Scenario 1 (221 $/kw Capacity Benefit)												
Production	$ 0	$ -	$ 0	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ 0	
SO2/NOx	$ (0)	$ (0)	$ -	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ (0)	$ (0)	
Insurance	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (279)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)	
Labor O&M	$ (125)	$ (125)	$ (125)	$ (127)	$ (130)	$ (133)	$ (135)	$ (138)	$ (141)	$ (143)	$ (922)	
Non-Labor O&M	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (41)	$ (42)	$ (42)	$ (43)	$ (287)	
Levelized Capital	$ -	$ -	$ -	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (43)	
Asset Retire Cost	$ 75	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 105	
Capacity Benefit	$ 12,799	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,799	
Write off/Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 12,669	$ (200)	$ (200)	$ (213)	$ (215)	$ (218)	$ (221)	$ (225)	$ (228)	$ (232)	$ 11,370	Operate
Scenario 2 (1000 $/MWh Purchase Market Price)												
Production	$ 2,135	$ 812	$ 78	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ 2,948	
SO2/NOx	$ (0)	$ (4)	$ (4)	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ (0)	$ (7)	
Insurance	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (279)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)	
Labor O&M	$ (125)	$ (125)	$ (125)	$ (127)	$ (130)	$ (133)	$ (135)	$ (138)	$ (141)	$ (143)	$ (922)	
Non-Labor O&M	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (41)	$ (42)	$ (42)	$ (43)	$ (287)	
Levelized Capital	$ -	$ -	$ -	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (43)	
Asset Retire Cost	$ 75	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 105	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 2,005	$ 608	$ (126)	$ (213)	$ (215)	$ (218)	$ (221)	$ (225)	$ (228)	$ (232)	$ 1,512	Operate
Scenario 3 (Scenario 1 and Scenario 2 Occur)												
Production	$ 2,135	$ 812	$ 78	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ 2,948	
SO2/NOx	$ (0)	$ (4)	$ (4)	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ (0)	$ (7)	
Insurance	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (279)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)	
Labor O&M	$ (125)	$ (125)	$ (125)	$ (127)	$ (130)	$ (133)	$ (135)	$ (138)	$ (141)	$ (143)	$ (922)	
Non-Labor O&M	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (41)	$ (42)	$ (42)	$ (43)	$ (287)	
Levelized Capital	$ -	$ -	$ -	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (43)	
Asset Retire Cost	$ 75	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 105	
Capacity Benefit	$ 12,799	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,799	
Write off/Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 14,805	$ 608	$ (126)	$ (213)	$ (215)	$ (218)	$ (221)	$ (225)	$ (228)	$ (232)	$ 14,311	Operate

Retire Haefling Units 1, 2 and 3
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 13	$ 21	$ 0	$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0	$ 32	
SO2/NOx	$ (0)	$ (9)	$ -	$ -	$ -	$ -	$ (0)	$ -	$ -	$ -	$ (8)	
Insurance	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (175)	
Air/Water Fees	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	
Labor O&M	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (8)	$ (8)	$ (50)	
Non-Labor O&M	$ (30)	$ (30)	$ (30)	$ (31)	$ (31)	$ (32)	$ (32)	$ (33)	$ (34)	$ (34)	$ (222)	
Levelized Capital	$ -	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (168)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 911	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ 298	
Other											$ -	
Total	$ 863	$ (178)	$ (191)	$ (191)	$ (192)	$ (193)	$ (194)	$ (194)	$ (195)	$ (196)	$ (293)	Retire

Scenario 1 (221 $/kw Capacity Benefit)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 13	$ 21	$ 0	$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0	$ 32	
SO2/NOx	$ (0)	$ (9)	$ -	$ -	$ -	$ -	$ (0)	$ -	$ -	$ -	$ (8)	
Insurance	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (175)	
Air/Water Fees	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	
Labor O&M	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (8)	$ (8)	$ (50)	
Non-Labor O&M	$ (30)	$ (30)	$ (30)	$ (31)	$ (31)	$ (32)	$ (32)	$ (33)	$ (34)	$ (34)	$ (222)	
Levelized Capital	$ -	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (168)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 7,944	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,944	
Write off/Depreciation	$ 911	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ 298	
Other											$ -	
Total	$ 8,807	$ (178)	$ (191)	$ (191)	$ (192)	$ (193)	$ (194)	$ (194)	$ (195)	$ (196)	$ 7,651	Operate

Scenario 2 (1000 $/MWh Purchase Market Price)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 1,685	$ 980	$ 117	$ 0	$ 0	$ 30	$ -	$ 0	$ 0	$ 0	$ 2,705	
SO2/NOx	$ 1	$ (7)	$ (3)	$ -	$ -	$ 1	$ (0)	$ -	$ -	$ -	$ (7)	
Insurance	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (175)	
Air/Water Fees	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	
Labor O&M	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (8)	$ (8)	$ (50)	
Non-Labor O&M	$ (30)	$ (30)	$ (30)	$ (31)	$ (31)	$ (32)	$ (32)	$ (33)	$ (34)	$ (34)	$ (222)	
Levelized Capital	$ -	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (168)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 911	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ 298	
Other											$ -	
Total	$ 2,535	$ 783	$ (76)	$ (191)	$ (192)	$ (161)	$ (194)	$ (194)	$ (195)	$ (196)	$ 2,381	Operate

Scenario 3 (Scenario 1 and Scenario 2 Occur)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 1,685	$ 980	$ 117	$ 0	$ 0	$ 30	$ -	$ 0	$ 0	$ 0	$ 2,705	
SO2/NOx	$ 1	$ (7)	$ (3)	$ -	$ -	$ 1	$ (0)	$ -	$ -	$ -	$ (7)	
Insurance	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (175)	
Air/Water Fees	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	
Labor O&M	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (8)	$ (8)	$ (50)	
Non-Labor O&M	$ (30)	$ (30)	$ (30)	$ (31)	$ (31)	$ (32)	$ (32)	$ (33)	$ (34)	$ (34)	$ (222)	
Levelized Capital	$ -	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (168)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 7,944	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,944	
Write off/Depreciation	$ 911	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ 298	
Other											$ -	
Total	$ 10,480	$ 783	$ (76)	$ (191)	$ (192)	$ (161)	$ (194)	$ (194)	$ (195)	$ (196)	$ 10,325	Operate

Retire Waterside Units 7-8
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	
SO2/NOx	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	
Insurance	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (195)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (12)	$ (12)	$ (13)	$ (13)	$ (13)	$ (13)	$ (14)	$ (14)	$ (14)	$ (14)	$ (92)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 717	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ 234	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 679	$ (120)	$ (121)	$ (122)	$ (122)	$ (122)	$ (122)	$ (122)	$ (123)	$ (123)	$ (58)	Retire

Scenario 1 (221 $/kw Capacity Benefit resulting from Capital/O&M expenses associated w/ HGPI)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	
SO2/NOx	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	
Insurance	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (195)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (12)	$ (12)	$ (13)	$ (1,013)	$ (13)	$ (13)	$ (14)	$ (14)	$ (14)	$ (14)	$ (869)	
Levelized Capital	$ -	$ -	$ -	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (1,610)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 4,855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,855	
Write off/Depreciation	$ 717	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ 234	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 5,534	$ (120)	$ (121)	$ (1,497)	$ (497)	$ (497)	$ (497)	$ (497)	$ (498)	$ (498)	$ 2,409	Operate

Scenario 2 (1000 $/MWh Purchase Market Price)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 100	$ 13	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -	$ 113	
SO2/NOx	$ (2)	$ (0)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2)	$ (4)	
Insurance	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (195)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (12)	$ (12)	$ (13)	$ (13)	$ (13)	$ (13)	$ (14)	$ (14)	$ (14)	$ (14)	$ (92)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 717	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ 234	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 775	$ (107)	$ (122)	$ (122)	$ (122)	$ (122)	$ (122)	$ (122)	$ (123)	$ (125)	$ 48	Operate

Scenario 3 (Scenario 1 and Scenario 2 Occur)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 100	$ 13	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -	$ 113	
SO2/NOx	$ (2)	$ (0)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2)	$ (4)	
Insurance	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (195)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (12)	$ (12)	$ (13)	$ (1,013)	$ (13)	$ (13)	$ (14)	$ (14)	$ (14)	$ (14)	$ (869)	
Levelized Capital	$ -	$ -	$ -	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (1,610)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 4,855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,855	
Write off/Depreciation	$ 717	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ 234	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 5,630	$ (107)	$ (122)	$ (1,497)	$ (497)	$ (497)	$ (497)	$ (497)	$ (498)	$ (500)	$ 2,515	Operate

Retire Paddy's Run Units 11-12
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)												
Production	$ 18	$ 15	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 32	
SO2/NOx	$ (4)	$ (6)	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -	$ (0)	$ (10)	
Insurance	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (127)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (51)	$ (52)	$ (55)	$ (58)	$ (59)	$ (60)	$ (61)	$ (62)	$ (63)	$ (65)	$ (406)	
Levelized Capital	$ (15)	$ (53)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (526)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 202	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ 66	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 131	$ (137)	$ (187)	$ (189)	$ (190)	$ (192)	$ (193)	$ (194)	$ (195)	$ (196)	$ (979)	Retire
Scenario 1 (221 $/kw Capacity Benefit resulting from Capital/O&M expenses associated w/ HGPI)												
Production	$ 18	$ 15	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 32	
SO2/NOx	$ (4)	$ (6)	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -	$ (0)	$ (10)	
Insurance	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (127)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (51)	$ (552)	$ (555)	$ (58)	$ (59)	$ (60)	$ (61)	$ (62)	$ (63)	$ (65)	$ (1,288)	
Levelized Capital	$ (15)	$ (203)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (2,206)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 7,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,724	
Write off/Depreciation	$ 202	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ 66	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 7,855	$ (787)	$ (987)	$ (489)	$ (490)	$ (492)	$ (493)	$ (494)	$ (495)	$ (496)	$ 4,182	Operate
Scenario 2 (1000 $/MWh Purchase Market Price)												
Production	$ 734	$ 365	$ 2	$ -	$ 1	$ 20	$ -	$ 0	$ -	$ -	$ 1,084	
SO2/NOx	$ (11)	$ (4)	$ (2)	$ -	$ -	$ (1)	$ -	$ (0)	$ -	$ (4)	$ (20)	
Insurance	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (127)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (51)	$ (52)	$ (55)	$ (58)	$ (59)	$ (60)	$ (61)	$ (62)	$ (63)	$ (65)	$ (406)	
Levelized Capital	$ (15)	$ (53)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (526)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 202	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ 66	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 840	$ 214	$ (187)	$ (189)	$ (190)	$ (173)	$ (193)	$ (194)	$ (195)	$ (201)	$ 63	Operate
Scenario 3 (Scenario 1 and Scenario 2 Occur)												
Production	$ 734	$ 365	$ 2	$ -	$ 1	$ 20	$ -	$ 0	$ -	$ -	$ 1,084	
SO2/NOx	$ (11)	$ (4)	$ (2)	$ -	$ -	$ (1)	$ -	$ (0)	$ -	$ (4)	$ (20)	
Insurance	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (127)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (51)	$ (552)	$ (555)	$ (58)	$ (59)	$ (60)	$ (61)	$ (62)	$ (63)	$ (65)	$ (1,288)	
Levelized Capital	$ (15)	$ (203)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (2,206)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 7,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,724	
Write off/Depreciation	$ 202	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ 66	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 8,564	$ (436)	$ (987)	$ (489)	$ (490)	$ (473)	$ (493)	$ (494)	$ (495)	$ (501)	$ 5,224	Operate

Retire Cane Run Unit 11
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7	
SO2/NOx	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (67)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (20)	$ (21)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (25)	$ (25)	$ (26)	$ (162)	
Levelized Capital	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (265)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 869	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ 284	
Other											$ -	
Total	$ 807	$ (165)	$ (166)	$ (167)	$ (168)	$ (168)	$ (169)	$ (169)	$ (170)	$ (170)	$ (208)	Retire

Scenario 1 (221 $/kw Capacity Benefit)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7	
SO2/NOx	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (67)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (20)	$ (21)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (25)	$ (25)	$ (26)	$ (162)	
Levelized Capital	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (265)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 3,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,089	
Write off/Depreciation	$ 869	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ 284	
Other											$ -	
Total	$ 3,896	$ (165)	$ (166)	$ (167)	$ (168)	$ (168)	$ (169)	$ (169)	$ (170)	$ (170)	$ 2,881	Operate

Scenario 2 (1000 $/MWh Purchase Market Price)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 155	$ -	$ 1	$ -	$ 1	$ 20	$ -	$ -	$ -	$ -	$ 168	
SO2/NOx	$ (0)	$ -	$ -	$ -	$ -	$ (2)	$ -	$ -	$ -	$ -	$ (2)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (67)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (20)	$ (21)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (25)	$ (25)	$ (26)	$ (162)	
Levelized Capital	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (265)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 869	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ 284	
Other											$ -	
Total	$ 955	$ (165)	$ (166)	$ (167)	$ (167)	$ (150)	$ (169)	$ (169)	$ (170)	$ (170)	$ (48)	Retire

Scenario 3 (Scenario 1 and Scenario 2 Occur)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 155	$ -	$ 1	$ -	$ 1	$ 20	$ -	$ -	$ -	$ -	$ 168	
SO2/NOx	$ (0)	$ -	$ -	$ -	$ -	$ (2)	$ -	$ -	$ -	$ -	$ (2)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (67)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (20)	$ (21)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (25)	$ (25)	$ (26)	$ (162)	
Levelized Capital	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (265)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 3,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,089	
Write off/Depreciation	$ 869	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ 284	
Other											$ -	
Total	$ 4,045	$ (165)	$ (166)	$ (167)	$ (167)	$ (150)	$ (169)	$ (169)	$ (170)	$ (170)	$ 3,042	Operate

Retire Zorn Unit 1

Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 5	$ 4	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 8	
SO2/NOx	$ (1)	$ (2)	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -	$ (0)	$ (3)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (61)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (19)	$ (19)	$ (20)	$ (21)	$ (22)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (151)	
Levelized Capital	$ -	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (227)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 126	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ 41	
Loisville Water Com	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 71	
Total	$ 111	$ (69)	$ (71)	$ (72)	$ (73)	$ (73)	$ (73)	$ (74)	$ (74)	$ (75)	$ (327)	Retire

Scenario 1 (221 $/kw Capacity Benefit resulting from Capital/O&M expenses associated w/ HGPI)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Yr NPV	
Production	$ 5	$ 4	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 8	
SO2/NOx	$ (1)	$ (2)	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -	$ (0)	$ (3)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (61)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (19)	$ (519)	$ (20)	$ (21)	$ (22)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (611)	
Levelized Capital	$ -	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (1,136)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 3,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,089	
Write off/Depreciation	$ 126	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ 41	
Loisville Water Com	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 71	
Total	$ 3,200	$ (719)	$ (221)	$ (222)	$ (223)	$ (223)	$ (223)	$ (224)	$ (224)	$ (225)	$ 1,394	Operate

Scenario 2 (1000 $/MWh Purchase Market Price)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Yr NPV	
Production	$ 322	$ 138	$ -	$ -	$ 1	$ 20	$ -	$ 0	$ -	$ -	$ 462	
SO2/NOx	$ (4)	$ (2)	$ -	$ -	$ -	$ (2)	$ -	$ (0)	$ -	$ (0)	$ (7)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (61)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (19)	$ (19)	$ (20)	$ (21)	$ (22)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (151)	
Levelized Capital	$ -	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (227)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 126	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ 41	
Loisville Water Com	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 71	
Total	$ 425	$ 65	$ (71)	$ (72)	$ (72)	$ (55)	$ (73)	$ (74)	$ (74)	$ (75)	$ 123	Operate

Scenario 3 (Scenario 1 and Scenario 2 Occur)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Yr NPV	
Production	$ 322	$ 138	$ -	$ -	$ 1	$ 20	$ -	$ 0	$ -	$ -	$ 462	
SO2/NOx	$ (4)	$ (2)	$ -	$ -	$ -	$ (2)	$ -	$ (0)	$ -	$ (0)	$ (7)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (61)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (19)	$ (519)	$ (20)	$ (21)	$ (22)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (611)	
Levelized Capital	$ -	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (188)	$ (1,136)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 3,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,089	
Write off/Depreciation	$ 126	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ (14)	$ 41	
Loisville Water Com	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 71	
Total	$ 3,515	$ (585)	$ (221)	$ (222)	$ (222)	$ (205)	$ (223)	$ (224)	$ (224)	$ (225)	$ 1,843	Operate

Appendix D

Total Cash Flows from a Regulated and Merchant Perspective

(Cases 2 and 3)

Total Cash Flows Associated with Group 3 Units
Regulated and Merchant Environment

Note: A postive NPV suggests retirement while a negative NPV suggests continued operation.

Units	Market Environment	Case	Assumptions	Total Cash Flow ($000) 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Year NPV Cash Flow ($000s) @ 8.74%	Retire or Operate
Green River 1-2	Regulated	Case 2	Base Assumptions	($1,194)	$1,072	$1,207	$1,285	$1,155	$1,068	$1,119	$1,386	$1,224	$1,206	$5,982	Retire
		Case 2	Scenario 1	($1,931)	$334	$470	$547	$417	$331	$382	$648	$486	$468	$775	Retire
		Case 2	Scenario 2	($1,812)	$802	$1,313	$1,341	$1,187	$1,146	$1,119	$1,484	$1,229	$1,270	$5,412	Retire
		Case 2	Scenario 3	($349)	$1,878	$3,690	$1,656	$1,047	$968	$1,027	$1,300	$1,144	$1,131	$9,603	Retire
		Case 2	Scenario 4	($1,704)	$871	$3,058	$975	$342	$309	$289	$661	$412	$457	$3,826	Retire
		Case 2	Scenario 5	($1,086)	$1,141	$2,953	$919	$309	$231	$289	$562	$406	$393	$4,396	Retire
	Merchant	Case 3	Base Assumptions	($1,016)	$705	$710	$626	$634	$641	$649	$657	$665	$674	$3,010	Retire
Tyrone 1-2	Regulated	Case 2	Base Assumptions	$78	$119	$119	$187	$120	$122	$124	$126	$129	$131	$872	Retire
		Case 2	Scenario 1	($893)	($852)	($852)	($784)	($851)	($849)	($847)	($845)	($842)	($840)	($5,982)	Operate
		Case 2	Scenario 2	($1,196)	($363)	$75	$187	$120	$122	$124	$126	$129	$131	($883)	Operate
		Case 2	Scenario 3	($2,167)	($1,334)	($896)	($784)	($851)	($849)	($847)	($845)	($842)	($840)	($7,737)	Operate
	Merchant	Case 3	Base Assumptions	$78	$119	$119	$187	$120	$122	$124	$126	$129	$131	$872	Retire
Haefling 1-3	Regulated	Case 2	Base Assumptions	($514)	$272	$92	$92	$93	$94	$95	$96	$96	$97	$217	Retire
		Case 2	Scenario 1	($1,118)	($332)	($512)	($511)	($510)	($510)	($509)	($508)	($507)	($507)	($4,043)	Operate
		Case 2	Scenario 2	($1,512)	($301)	$23	$92	$93	$75	$95	$96	$96	$97	($1,377)	Operate
		Case 2	Scenario 3	($2,116)	($905)	($580)	($511)	($510)	($528)	($509)	($508)	($507)	($507)	($5,638)	Operate
	Merchant	Case 3	Base Assumptions	($538)	$238	$65	$56	$54	$45	$32	$28	$24	$20	($97)	Operate
Waterside 7-8	Regulated	Case 2	Base Assumptions	($305)	$72	$72	$72	$72	$73	$73	$73	$73	$73	$134	Retire
		Case 2	Scenario 1	($1,461)	($984)	($984)	$2,072	($1,059)	($1,053)	($1,048)	($1,043)	($1,039)	($1,034)	($5,290)	Operate
		Case 2	Scenario 2	($362)	$64	$73	$72	$72	$73	$73	$73	$73	$75	$71	Retire
		Case 2	Scenario 3	($462)	$64	$73	$3,128	($3)	$3	$8	$13	$18	$23	$2,102	Retire
	Merchant	Case 3	Base Assumptions	($347)	$11	$30	$17	$12	$1	($16)	($22)	($28)	($35)	($342)	Operate
Paddy's 11-12	Regulated	Case 2	Base Assumptions	$13	$296	$296	$45	$46	$48	$50	$51	$53	$54	$742	Retire
		Case 2	Scenario 1	($574)	$992	$961	($600)	($594)	($589)	($583)	($578)	($574)	($571)	($1,385)	Operate
		Case 2	Scenario 2	($410)	$87	$296	$45	$46	$37	$50	$51	$53	$57	$120	Retire
		Case 2	Scenario 3	($997)	$782	$961	($600)	($595)	($600)	($583)	($578)	($574)	($568)	($2,007)	Operate
	Merchant	Case 3	Base Assumptions	($36)	$221	$240	($31)	($36)	($50)	($74)	($82)	($90)	($98)	$101	Retire
Cane Run 11	Regulated	Case 2	Base Assumptions	($254)	$76	$76	$77	$77	$78	$78	$78	$78	$79	$214	Retire
		Case 2	Scenario 1	($489)	($159)	($158)	($158)	($157)	($157)	($157)	($157)	($156)	($156)	($1,442)	Operate
		Case 2	Scenario 2	($342)	$76	$76	$77	$77	$67	$78	$78	$78	$79	$119	Retire
		Case 2	Scenario 3	($577)	($159)	($159)	($158)	($158)	($168)	($157)	($157)	($156)	($156)	($1,538)	Operate
	Merchant	Case 3	Base Assumptions	($267)	$51	$60	$55	$53	$49	$42	$40	$37	$35	$27	Retire
Zorn 1	Regulated	Case 2	Base Assumptions	($60)	$271	$19	$20	$20	$21	$22	$22	$23	$24	$295	Retire
		Case 2	Scenario 1	($295)	$1,318	($246)	($243)	($240)	($238)	($235)	($233)	($231)	($230)	($317)	Operate
		Case 2	Scenario 2	($248)	$191	$19	$20	$20	$11	$22	$22	$23	$24	$26	Retire
		Case 2	Scenario 3	($482)	$1,238	($246)	($243)	($241)	($248)	($235)	($233)	($231)	($230)	($585)	Operate
	Merchant	Case 3	Base Assumptions	($84)	$234	($7)	($15)	($17)	($23)	($33)	($36)	($40)	($43)	$4	Retire